Submission to the AER on its Preliminary Determination

3 July 2015

Our submission

Ergon Energy has revised parts of the October Regulatory Proposal to reflect a number of positions adopted by the Australian Energy Regulator (AER) in its Preliminary Determination. Where more up-to-date information is available, we have also incorporated this in our revised Regulatory Proposal.

We have not made revisions in circumstances where we believe the AER's Preliminary Determination was incorrect. In those circumstances we have provided further evidence which substantiates our October Regulatory Proposal and/or demonstrates why the AER's decision is incorrect.

In preparing our revised Regulatory Proposal, Ergon Energy has taken into account stakeholder feedback to the AER's process as well as other factors influencing possible changes to what we previously proposed.

Ergon Energy considers our revised Regulatory Proposal meets the long-term interests of customers, in terms of price, reliability, and security of supply and safety.

Highlights

- We were optimistic in October 2014 that with improving financial markets, the costs of financing our investments would fall. This has occurred and our required revenues are now lower than what we forecast in our October Regulatory Proposal.

  We have updated our proposal to reflect these improved financing conditions. We have not made the equivalent changes to the rate of return parameters the AER determined in April 2015. We explain in this response that the AER has set these parameters too low.
- Our revised capital expenditure forecasts are slightly lower, reflecting updated market expectations of cost inputs into the future. We have not adjusted these to the extent determined by the AER. Its Preliminary Determination contained errors (which the AER has conceded) that will need to be adjusted in the final decision.
- We have changed our operating expenditure forecasts but cannot accept the AER's assessment process to be a reasonable one, having regard to our statutory requirements. We outline our main objections to the Preliminary Determination in this submission response.

Contents

1. Introduction

On 31 October 2014, Ergon Energy submitted our initial Regulatory Proposal to the Australian Energy Regulator (AER) for the regulatory control period commencing on 1 July 2015 and ending on 30 June 2020.[1] Our October proposal set out our regulated distribution services, and the revenue and prices associated with them, for the five year period.

The AER released its Preliminary Determination on our proposal on 30 April 2015.[2]

Under transitional arrangements, the AER must revoke and substitute our Preliminary Determination by 31 October 2015 (the Substitute Determination).[3] This process allows Ergon Energy to lodge a submission for further consideration by the AER, including in the form of revisions to our October Regulatory Proposal.[4]

This document, and associated attachments and models, form part of our submission to the AER.

1.1. Overview

We have reviewed the AER's Preliminary Determination as well as stakeholder views in the context of the proposal we lodged last year. We have also surveyed our operating environment and market conditions since we lodged our proposal. Based on our review of these matters, Ergon Energy has amended many aspects of our October Regulatory Proposal.

However, in a number of areas we have considered the AER's Preliminary Determination, but have not changed our Regulatory Proposal. This is because the AER's Preliminary Determination in these areas is incorrect or has not properly taken into account the impact on customers. We continue to oppose the AER's decision making process around the rate of return and operating expenditure, both of which rely on processes independent of the National Electricity Rules (NER) requirements and have not been properly reconciled back to the objectives within the NER and the National Electricity Law (NEL). The AER has already conceded there are errors in its Preliminary Determination which require amendment. We outline our proposed approach to correcting these, and other errors we have identified in our process of reviewing the AER's material.

We have provided further information to support our October Regulatory Proposal in respect of certain categories of capital expenditure, while also highlighting areas where the AER has made an incorrect assumption or decision. We have provided detailed explanations of the concerns we have with the AER's decision on Default Metering Services, and our proposed solution to resolve them.

In these areas we submit that the AER should review the evidence and adopt what we have proposed – either in our October Regulatory Proposal or as amended in our revised Regulatory Proposal. The rationale for why the AER's preliminary decision was incorrect is articulated in this submission and supporting documentation.

Finally, Ergon Energy has undertaken additional consumer engagement activities since the lodgement of our October Regulatory Proposal. This has reconfirmed general community support for our proposed direction for 2015-20 – that is, delivering peace of mind from a safe, reliable and secure electricity supply, greater choice and control in how the network is used (connecting solar and other technologies) and through other service improvements, all for the best possible price.[5]

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[1] http://www.ergon.com.au/futureinvestment.
[2] http://www.aer.gov.au/node/20186.
[3] NER, clause 11.60.4(c).
[4] NER, clause 11.60.4(b).
[5] *Colmar Brunton – Customers' Investment Priorities*.

In general, our customers and stakeholders are telling us that they still seek price relief, but only where it does not make any significant changes to supply reliability, network maintenance and safety standards, our customer service offering or things like the management of local depots or our storm or disaster response capability. This has been our focus throughout the development and review of our Regulatory Proposal.

As a result, our revised Regulatory Proposal will see us pass on the savings we have been able to achieve as a significant reduction to our charges for the use of the distribution network in 2015-16, in line with the AER's Preliminary Determination, and then see what we charge stabilise at 2014-15 levels for the remaining years of the regulatory control period.

The other service commitments we have made to our customers, associated with our overall direction, have all continued to inform our investment plans as we have revised our Regulatory Proposal.

Our refreshed best possible price commitment

After reducing charges for the use of our network in 2015-16, we're targeting to keep charges overall at 2014-15 levels for the remaining four years out to 2020.

1.2. Documentation suite

This document provides an overall picture of our response to the AER on its Preliminary Determination. It highlights areas of the AER's Preliminary Determination where Ergon Energy agrees or disagrees with the positions adopted by the AER and summarises our main concerns. It also responds, at a high level, to stakeholder feedback received to date on our proposal and outlines our latest consumer engagement activities.

More detailed responses to various aspects of the Preliminary Determination have been made in separate submissions. These documents are categorised by topic (e.g. the rate of return). Revisions to our initial proposal are clearly identified in these documents. A number of other documents are also provided to support the arguments presented in the individual submissions.

Finally, Ergon Energy has submitted a revised Regulatory Proposal. The revised Regulatory Proposal takes the form of the initial proposal, but it has been updated as necessary to reflect our response to the AER's Preliminary Determination and any other updated information. Documents that accompanied our October Regulatory Proposal have also been resubmitted, either in their current form or updated to reflect new numbers and/or approaches.

A graphical depiction of the suite of information accompanying our submission is shown in Figure 1.

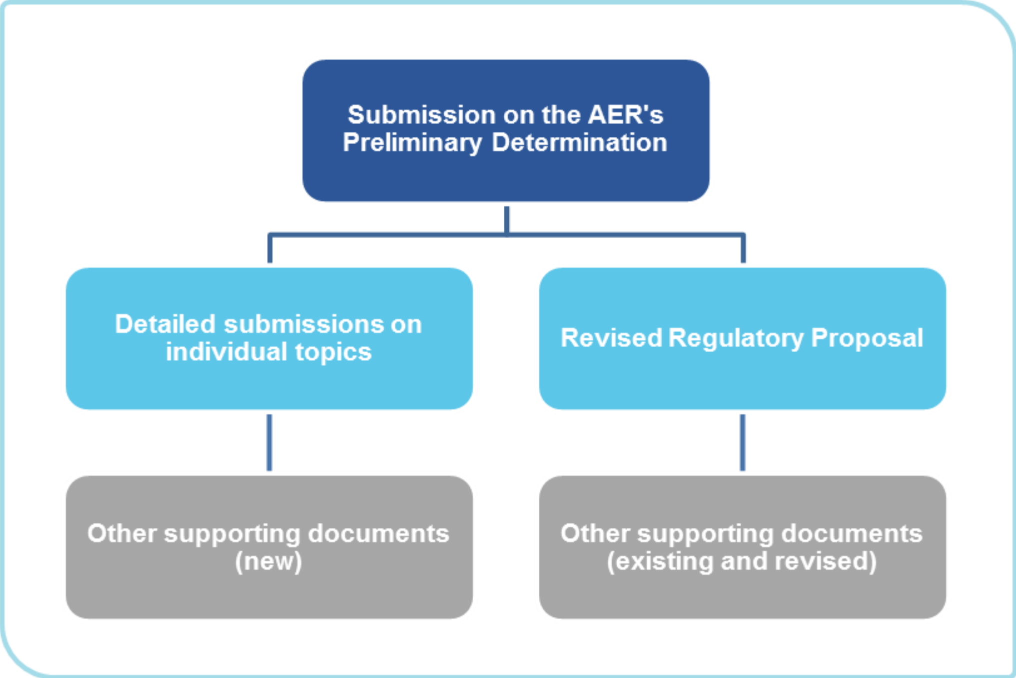

Figure 1: Overall structure of our submission to the AER

2. Consumer engagement

2.1. Our approach in the October Regulatory Proposal

To ensure our investment proposals are aligned and reflect the long-term interests of our customers, our Regulatory Proposal preparation included a coordinated, multi-channel customer/community engagement program. Our aim has been to ensure that the views and concerns of our customers and other stakeholders informed our investments priorities and overall Regulatory Proposal.

Through an ongoing conversation with our customers and the communities we provide services to, we have a deep understanding of the level of concern in the community about rising electricity prices. However, we also appreciate that our customers still want the peace of mind that comes from having a safe, dependable electricity service and that they are increasingly seeking greater choice and control around their energy supply solutions. We reiterate the expectations of our customers below.

2.1.1. Peace of mind from a safe, dependable service

Our customers do not want us to compromise on safety. They see electricity reliability as important and recognise that it has improved. They are no longer looking for higher reliability standards (except in areas where reliability is still poor).

They value our local presence, and our disaster response, and see investing in the network's resilience to severe weather as important. Our customers are looking for further improvements around the delivery of new connections, including solar connections.

Our customers view Ergon Energy as a good corporate citizen, with responsibilities around electrical safety, emergency management, local employment and apprenticeships, energy conservation, minimising the impact of new electricity infrastructure on the community, and community participation.

2.1.2. A future of greater choice and control

A significant proportion of our customers feel they have done all they can to reduce their usage and to save costs, and need further tariff options in order to respond. Others are investing in technologies, such as solar and battery storage, as a means to control costs. In summary:

- Our customers are looking for ways to help them save on their bill and want more choices around how they connect to the network.
- Our customers want us to look to a future where customers are empowered with new electricity supply solutions, and to consider transitioning towards a smart network.
- Our customers increasingly want to be informed on energy-related matters.

2.1.3. Best possible price, best overall value

The cost of electricity is a significant issue for our customers, with affordability concerns rising as sharply as prices have risen. While our customers generally do not understand what has driven prices up, they expect Ergon Energy to respond as part of our role as the face of the industry in regional Queensland.

We did see some divergence between the response from residential customers who generally preferred prices to stabilise and responses from our business customers who see price relief as a key objective – they are no longer willing to pay more for further service improvements. However, the customer experience, reliability of supply and our corporate responsibility performance remain important to our customers' value perceptions.

Our October Regulatory Proposal noted that we had worked hard behind the scenes to make savings in our operational and capital expenditure programs in the hope that this could address customer concerns around affordability. These initiatives were enhanced by expectations of more favourable finance costs leading into the regulatory control period 2015-20. Our ability to maintain what we charge though to 2020 being stabilised at 2014-15 levels was achieved by:

- reducing our total expenditure by more than 20 per cent when compared to the AER's approved allowances for the regulatory control period 2010-15
- targeting overall expenditure forecasts in 2015-20 which are more than $1 billion[6] below the expenditure levels we achieved in 2010-15.

2.2. Engagement and the Preliminary Determination

The AER's Preliminary Determination has dramatically reduced the revenues allowed by Ergon Energy to provide distribution services. While this was largely based on the AER's decision to apply lower financing costs in determining future revenues compared to what Ergon Energy proposed, the AER also made deep expenditure reductions to the programs that we had proposed on the basis that

> "…consumers have been saying to us that the levels of expenditure sought by the businesses are not sufficiently justified."[7]

To explore this further, and ensure our customer insights were up to date, we undertook additional customer and stakeholder engagement activities in May and June 2015. This engagement has allowed us to explore our customers' views on the AER's Preliminary Determination generally and reassess the level of support for our overall proposal and investment priorities, and to explore the paths we could potentially take in realising greater efficiencies going forward.

We continued our engagement with our consumer advocacy groups and community leaders; with two face to face sessions hosted and a webinar to help broaden our regional stakeholder engagement.

Those active in these sessions were largely continuing to question how further reductions could be achieved, generally expecting greater price relief for those they represent than the revenue determination process itself has been able to deliver. These conversations were in line with the submissions made to the AER regarding our October Regulatory Proposal, which are detailed in this submission. Concerns remained predominantly around the rate of return. In short, many consumer advocacy groups want Ergon Energy to accept a lower rate of return than what we are proposing.

We also undertook supplementary quantitative residential customer research in June 2015.[8] This research found our customers more broadly remain supportive of our proposal (67 per cent highly supportive) in line with earlier validation research. There are concerns across our customer base

[6] 2014-15 dollars
[7] AER (2015), *AER expects decisions to lower electricity bills for Queensland customers*, Media release, 30 April 2015.
[8] *Colmar Brunton – Customers' Investment Priorities*.

about Ergon Energy changing the way we do business to achieve greater price reductions than currently proposed.

In summary:

- 49 per cent were satisfied with more moderate reductions in network charges in our revised Regulatory Proposal, and were not generally supportive of Ergon Energy making significant changes to the way we do business.
- 38 per cent would prefer a greater reduction in network charges. However, they had concerns about how the savings would be achieved.
- 13 per cent expected a much larger reduction, and were not concerned where or how the savings are made.

This research is available in the document, *Colmar Brunton – Customers' Investment Priorities*.

3. Key elements of our response

3.1. Correction of errors

A number of errors have been identified in the Preliminary Determination, both by the AER and by Ergon Energy. A summary of the key errors are identified below.

3.1.1. Cost escalation

On 8 May 2015, Ergon Energy wrote to the AER regarding two cost escalations errors:

1. the deduction from the Standard Control Services capital expenditure of materials and labour cost escalators referring to all Direct Control Services capital expenditure, rather than the escalation component relating solely to Standard Control Services
2. the removal of all Consumer Price Index (CPI) and non-CPI escalations between 2012-13 and 2019-20.

In response, the AER advised that it intended to correct for these errors in the Substitute Determination.[9] This is because the AER considered the revenue effects of adjusting for these errors did not warrant an immediate adjustment for inclusion in prices for 2015-16.

Further details of the error and the proposed correction can be found in Chapter 9.

3.1.2. Formulae for Standard and Alternative Control Services

Following the release of the Preliminary Determination, the AER was made aware of issues associated with the revenue cap formula and quoted services formula. Specifically:

- the parameter for Distribution Use of System (DUOS) under/over recoveries from previous years ($DUOS_t$) was not included in the revenue cap formula, when it should have been
- the quoted services formula incorrectly described that the Contractor Services and Materials components should be escalated annually by ΔCPI.[10]

The AER required Ergon Energy to include the $DUOS_t$ parameter in the revenue cap formula and not apply CPI adjustment to quoted services in our 2015-16 Pricing Proposal. Further, it indicated that it would make the necessary amendments in the Substitute Determination.

Our response on these errors can be found in Sections 17 and 19.1.

3.1.3. Unexplained capital expenditure

We have found that the AER has misinterpreted the information in our October Regulatory Proposal and incorrectly formed the view that a residual amount of capital expenditure of $33 million is "unexplained". The "unexplained" capital expenditure is due to different escalation methodologies applied to re-state forecast expenditure in $2014-15 in:

- the Reset RIN.
- the Forecast Expenditure Summary documentation.

The Reset RIN forecasts include full labour, materials and CPI cost escalation, while the expenditure stated in the Forecast Expenditure Summary documentation only includes escalation for CPI.

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[9] AER (2015), Letter to Mr Gordon Taylor (Acting Chief Executive), 20 May 2015, p2.
[10] Ibid.

Our supporting submission, *Reset RIN Material Issues*, provides further information on this error.[11]

3.1.4. Exclusion of gifted and contributed expenditure in revenue modelling

Our analysis of the AER's models indicates that the AER has removed from our proposed Post Tax Revenue Model (PTRM) all gifted and contributed assets associated with Large Customer Connections in the regulatory control period 2015-20. There is no explanation of its reasons for this and we assume this is an oversight by the AER. The inclusion of these values does not impact the value of the Regulatory Asset Base (RAB) for Standard Control Services (reflecting the prepayment, contribution of gifting). However, the omission of the values from the PTRM means that the tax allowance is understated.

We explain this error in more detail in our supporting submission SCS *Building Blocks, Control Mechanism and Pricing.* Our revised Regulatory Proposal continues to account for these assets in the normal convention.

3.1.5. October Regulatory Proposal

As part of our own review of the October Regulatory Proposal, Ergon Energy has found errors in some inputs which we have sought to correct through the resubmission of materials and Regulatory Information Notice (RIN) tables. These errors are identified in this submission document and supporting documentation.

For example, we have identified a material error relating to our proposed Standard Control Services capital expenditure for metering. This error affects multiple line items in Table 2.1.1 of our Reset RIN. Our supporting submission, *Reset RIN Material Issues*, provides further information on this error and provides a corrected table.

3.1.6. Errors in operating environment factor adjustments

On 19 June 2015, the AER also advised Ergon Energy that it had made clinical errors in the calculation of the operating environmental factors. The AER indicated that it would take these errors into account in its Substitute Determination.

3.2. Role of benchmarking

The AER's decision on Ergon Energy's operating expenditure forecast is heavily influenced by evidence provided by its consultants. Using this information, the AER recreates a forecast for Ergon Energy that is intended to represent the expenditure forecast of a benchmark efficient firm.

Many network service providers (NSPs), including Ergon Energy, are concerned with this new approach to forecasting which appears to put to one side the underlying revealed and recurrent costs of the business and creates different forecasts using quite complicated modelling and analysis.

In our response to the AER's Issues Paper and determinations for other businesses, we have provided compelling evidence which has questioned the AER's approach. Adjustments have been made by the AER to their approach since the draft determination for New South Wales (NSW) and the Australian Capital Territory (ACT), which has lessened the impact for Ergon Energy.

[11] *Reset RIN Material Issues* also corrects for other errors we have adjusted as a result of our review of materials.

Notwithstanding these adjustments, we still believe there are material problems with the way the AER is approaching its task which need to be rectified. Our chapter on operating expenditure forecasts and supporting information outline these problems in more detail.

3.3. Rate of return

The AER's preliminary decision on the rate of return remains of concern to Ergon Energy. We have revised our rate of return to take into account changes to market conditions. We have also revised our approach to the cost of debt to reflect the AER's updated views on the debt management strategy for their benchmark firm.

Our approach to estimating the expected return on equity continues to differ from the AER's. Estimating the return on equity must take into account all relevant evidence, and where that evidence is relevant and probative as to the required return on equity, give it a direct role in the estimation process. The AER's approach does not do this. Rather, it relies on its foundation model both to set the rate of return and to justify the rejection of other approaches. This is despite recent changes that were made to the NER with the explicit intention of allowing other evidence and models to be considered.

Our approach to estimating the cost of debt was broadly consistent with the AER's Rate of Return Guideline (the Guideline). However, the AER has considered new evidence for the efficient cost of debt for the benchmark firm, and we have taken this into account when revising our proposal.

4. Annual revenue requirement

This section summarises our response to the AER's decision on the Annual Revenue Requirement (ARR). The ARR is the amount Ergon Energy is able to recover from customers for the provision of Standard Control Services in each regulatory year.[12] It is determined by adding together the following building blocks:

- return on capital
- return of capital (depreciation)
- operating expenditure
- tax allowance
- revenue increments/decrements.

X-factors are then applied to smooth the ARRs over the regulatory control period.

4.1. Preliminary Determination

4.1.1. Revenue requirements

The AER did not accept our proposed total revenue requirement of $8,228.6 million. Instead, the AER determined a total revenue requirement of $6,012.6 million. This is a reduction of $2,216.1 million or 26.9 per cent.

Table 1 provides the AER's preliminary determination on the ARRs, broken down by each building block component, and the X-factors to apply in the regulatory control period 2015-20.

Table 1: AER's preliminary determination on Ergon Energy's ARRs, 2015-20

$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Return on capital	590.8	617.0	640.4	658.9	674.6
Regulatory depreciation	106.7	121.2	137.3	147.2	142.3
Operating expenditure	327.5	342.1	356.4	372.9	389.0
Revenue adjustments	91.9	49.1	66.9	(21.4)	(2.3)
Net tax allowance	36.3	38.8	41.2	44.8	43.1
Annual revenue requirement (unsmoothed)	1,153.1	1,168.2	1,242.3	1,202.3	1,246.7
Annual expected revenue (excl. additionals)	**1,137.7**	**1,096.7**	**1,282.1**	**1,262.2**	**1,242.7**
X-factor	36.63%	6.00%	(14.00%)	4.00%	4.00%
Additional amounts in DUOS	424.3	331.7	104.9	102.1	99.2

[12] The ARR is determined using the PTRM. The revenue cap for any given year includes the ARR (or 'Allowable Revenue') plus other adjustments such as amounts associated with the occurrence of any pass through event.

$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Annual expected revenue (smoothed - incl. additionals)	**1,562.0**	**1,428.4**	**1,387.0**	**1,364.3**	**1,341.9**
Annual change in revenue - incl. additionals	(10.8%)	(8.6%)	(2.9%)	(1.6%)	(1.6%)

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 1 – Annual revenue requirement*, April 2015, p7.

4.1.2. Revenue smoothing

Typically, X-factors are only applied to revenue requirements included in the PTRM. This means the smoothing of revenues excludes other adjustments to the ARR undertaken in the annual pricing proposal process (e.g. cost pass through amounts associated with the Solar Bonus Scheme). Since these adjustments are sizable in the regulatory control period 2015-20, the AER took them into account in determining the smoothed revenue path. That is, the total DUOS revenue, including the other adjustments, will be smoothed overall.

The AER's 'smoothing profile', which incorporates both DUOS charges and the recovery of jurisdictional scheme amounts, differed slightly to the approach proposed by Ergon Energy. We adopted a smoothing profile which excluded feed-in tariff (FiT) recoveries.

4.1.3. Revenue increments or decrements

Table 2 sets out the revenue increments or decrements arising from the operation of a control mechanism or schemes that applied in the regulatory control period 2010-15.

Table 2: AER's preliminary determination on Ergon Energy's revenue increments/decrements, 2015-20

$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
EBSS	35.4	51.3	69.2	(19.2)	0.0
DMIA	1.0	1.1	1.1	1.1	1.1
Closing balance of DUOS unders/overs account as at 30 June 2015	58.6	n/a	n/a	n/a	n/a
Shared assets	(3.1)	(3.2)	(3.3)	(3.4)	(3.5)
Total	**91.9**	**49.1**	**66.9**	**(21.4)**	**(2.3)**

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 1 – Annual revenue requirement*, April 2015, p15.

4.1.4. Shared assets

In our October Regulatory Proposal, Ergon Energy proposed to apply a revenue adjustment to remove the component of shared assets that are used for unregulated services from the total annual revenue. The AER accepted our updated shared asset revenue adjustments.[13]

[13] Updated shared asset adjustments were provided in February 2015, in response to an information request from the AER.

We also proposed to do the same for assets that provide both Standard Control Services and Alternative Control Services. The AER did not support this proposal and instead removed the value of assets providing Alternative Control Services from the RAB.

4.2. Stakeholder feedback

Rising revenues and electricity prices are a key concern for our customers and other stakeholders. This theme has remained prevalent during consultation on our October Regulatory Proposal, with many stakeholders calling on the AER and Ergon Energy to deliver lower prices in the regulatory control period 2015-20.[14]

We note the Consumer Challenge Panel (CCP) also commented on our proposed revenues at the public forum held in December 2014, stating they are much higher than actual or allowed revenue in the regulatory control period 2010-15.[15]

Comments received on the various building block components are discussed elsewhere in this submission.

4.3. Other influencing factors

The ARR is affected by changes to the underlying building block components. Factors influencing each of these components are discussed in other sections of this submission.

4.4. Our response

The AER's decision to reduce our total revenue requirements by over 25 per cent to $6,021.5 million was not correct for the following reasons:

- There are errors in the AER's determination which make some of the inputs lower than they should be.
- The AER overlooked the need to incorporate certain capital expenditure inputs in its revenue models.
- The AER has deferred the depreciation allowance in the regulatory control period 2015-20 which unnecessarily increases the value of the RAB in 2020.
- The rate of return set by the AER is too low. Proper regard should be given to the NER when setting the rate of return.
- The AER has substituted a capital expenditure forecast that is too low – even after errors are accounted for.
- The AER has made adjustments to the RAB that are outside its powers to do so under the NER.
- The operating expenditure forecast determined by the AER has been subjectively determined using a single point estimate and has been set too low, with little regard for the realistic expectations of the expenditure required by Ergon Energy to provide services to customers in regional Queensland.

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[14] See, for example, Cotton Australia (2015), *Submission to the AER, Qld Electricity Distribution Regulatory Proposals 2015-16 to 2019-20,* January 2015, p12; QCOSS (2015), *Understanding the long term interests of electricity customers: Submission to the AER's Queensland electricity distribution determination 2015-2020,* 30 January 2015, pp11-14; and Chamber of Commerce and Industry Queensland (2015), *Submission to the AER on Ergon Energy's Regulatory Proposal for the 2015-2020 Revenue Determination*, 30 January 2015, p4.
[15] Bruce Mountain (2014), *Energex and Ergon's 2015-2020 proposal: initial comments*, Presentation at the AER's Public Forum, 9 December 2014, p2.

Consequently, we have not revised our October Regulatory Proposal to reflect the AER's Preliminary Determination on the ARRs.

Further, we note the AER has adopted a smoothing profile which accommodates forecast recovery of jurisdictional scheme amounts. We do not see merit in this approach as the forecast jurisdictional scheme amounts may be volatile. In addition, the recovery of jurisdictional scheme amounts is not relevant to the distribution services we provide. Instead, they represent a pass through of costs, similar to Transmission Use of System (TUOS) prices. Our preference is to smooth prices based on our part of the customer's bill, which is what we originally proposed.

Finally, Ergon Energy has amended our ARRs based on changes we have made to the underlying building block inputs. The basis of these changes is summarised in other chapters in this submission, and relate to key inputs such as the rate of return.

These changes are reflected in:

- Chapter 3 of the Regulatory Proposal
- *01.01.02 – (Revised) The Effect of Transitional Arrangements*
- *03.01.01 – (Revised) Ergon Energy's Building Block Components*
- *03.01.02 – (Revised) Other Revenue Adjustments.*

Our detailed response on the above matters is contained in *SCS Building Blocks, Control Mechanism and Pricing – Response*.

5. Regulatory Asset Base

This section summarises our response to the AER's decision on the RAB. The RAB represents the remaining value of all the capital assets we have previously made and that is still required to be recovered from customers, taking into account various factors. We have provided an overview of our response below, with more detail available in *SCS Building Blocks, Control Mechanism and Pricing – Response*.

5.1. Preliminary Determination

5.1.1. Opening RAB

The AER did not accept our proposed opening RAB value of $10,041.54 million as at 1 July 2015. Instead, the AER substituted its own value of $10,102.2 million. In doing so, the AER:

- applied the remaining asset lives approved in the 2010-15 Distribution Determination
- removed the movement in capitalised provisions from capital expenditure
- adjusted disposals
- adjusted equity raising costs
- rejected the inclusion of the Hayman Island undersea cable in the RAB
- removed from the RAB an estimated value of the proportion of assets that currently provide Alternative Control Services
- adjusted the amount removed from the RAB for meters (based on the reclassification of Default Metering Services).

A summary of the calculations made to derive the opening RAB is shown in Table 3.

Table 3: AER's preliminary determination on Ergon Energy's opening RAB, 2010-15

$m (nominal)	2010-11 Actual	2011-12 Actual	2012-13 Actual	2013-14 Actual	2014-15 Estimate
Opening RAB	7,148.9	7,870.5	8,393.0	9,072.3	9,681.3
Capital expenditure	809.5	748.3	836.5	743.8	885.9
Inflation indexation on opening RAB	238.3	124.7	210.0	265.8	217.8
less straight-line depreciation	326.3	350.5	367.2	400.5	397.2
Closing RAB	**7,870.5**	**8,393.0**	**9,072.3**	**9,681.3**	**10,387.9**
Difference between estimated and actual capital expenditure	-	-	-	-	(132.8)
Return on difference for 2009-10 capital expenditure	-	-	-	-	(78.3)
Closing RAB as at 30 June 2015	-	-	-	-	10,176.8
ACS (metering and other) assets removed	-	-	-	-	(74.6)
Opening RAB as at 1 July 2015	-	-	-	-	**10,102.2**

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 2 – Regulatory asset base*, April 2015, p7.

5.1.2. Closing RAB

The AER substituted our proposed closing RAB value of $12,867.0 million, with their own value of $11,773.7 million. This reflects its decision to reduce the capital expenditure and regulatory depreciation allowances, as well as the opening RAB value. A summary of the roll forward values determined by the AER is provided in Table 4.

Table 4: AER's preliminary determination on Ergon Energy's forecast RAB, 2015-20

$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Opening RAB	10,102.2	10,551.0	10,951.5	11,266.7	11,535.2
Capital expenditure	555.4	521.7	452.5	415.7	380.8
Inflation indexation on opening RAB	257.6	269.0	279.3	287.3	294.1
Less: straight-line depreciation	364.3	390.2	416.6	434.5	436.4
Closing RAB	**10,551.0**	**10,951.5**	**11,266.7**	**11,535.2**	**11,773.7**

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 2 – Regulatory asset base*, April 2015, p7.

5.1.3. Depreciation approach

The AER determined to apply the forecast depreciation approach to establish the opening RAB value as at 1 July 2020.

5.2. Stakeholder feedback

In its Issues Paper, the AER stated that our RAB is continuing to grow, despite lower capital expenditure being proposed and weak demand forecasts.[16] The AER indicated that it will investigate this issue. The CCP also raised similar concerns at the public forum held on 9 December 2014.[17]

A number of stakeholders requested the AER to carefully examine past and proposed capital expenditure to ensure expenditure is prudent and efficient.[18] The Bundaberg Regional Irrigators Group surmised that the RAB is “guaranteeing profits and escalating price increases”.[19] Stakeholders also suggested that the RAB should be re-valued.[20]

[16] AER (2014), *Issues paper: Qld electricity distribution regulatory proposal 2015–16 to 2019–20,* December 2014, pp9, 11 and 19.
[17] Bruce Mountain, Op. cit, p3.
[18] Darling Downs Cotton Farmers (2015), *RE: QLD Electricity Distribution Regulatory Proposals 2015-2020,* 29 January 2015, p1; Cotton Australia, Op. cit, p8; and Canegrowers Isis Ltd (2015), *Re: Qld electricity distribution regulatory proposals 2015-16 to 2019-20,* 30 January 2015, p3.
[19] Bundaberg Regional Irrigators Group (2015), *Re: Submission to AER regarding Ergon Energy’s regulatory proposal,* 30 January 2015, p3.
[20] Canegrowers (2015), *Ergon Energy and Energex – Network Distribution Resets 2015-20,* 30 January 2015, p4; Canegrowers Isis Ltd, Op. cit, p2; Electrical Trades Union of Australia (2015), *Energex and Ergon Regulatory Proposals 2015-20 and Issues Paper,* January 2015, p5; National Irrigators’ Council (2015), *Re: Submission to the AER Queensland electricity distribution regulatory proposals 2015-16 to 2019-20,* 30 January 2015, p2; and Cummings Economics (2015), *Submission to the AER by Cummings Economics on behalf of a Network of Electricity Users in Far North Queensland*, 30 January 2015, 30 January 2015, p34; and SPA Consulting Engineers (QLD) Pty Ltd (2015), *Submission to the AER, Queensland Distribution Determination for the period 2015-2020*, 30 January 2015, p4.

Some stakeholders also called on the AER to review the existing rules for determining the RAB, such as the application of an annual CPI adjustment.[21]

Finally, the Urban Development Institute of Australia and Australians in Retirement organisation queried whether gifted assets are included in the RAB.[22]

5.3. Other influencing factors

Ergon Energy has more up-to-date capital expenditure, disposal and regulatory depreciation estimates for 2014-15 than those relied on by the AER in its Preliminary Determination. These estimates affect the opening RAB value.

Proposed changes to our forecast capital expenditure (see Chapter 9), regulatory depreciation (see Chapter 8) and inflation rates also impact the forecast RAB values.

5.4. Our response

Ergon Energy has revised the RAB in our Regulatory Proposal to account for amendments we have made to capital expenditure, inflation and the rate of return. Our approach on these inputs is outlined in other chapters. Our opening RAB value has also been amended to reflect updated 2014-15 estimates.

We have reviewed the AER's determination in relation to equity raising costs, opening remaining asset lives and disposals. In response, we have:

- updated our opening RAB so it is consistent with the AER's revisions to remaining lives at the beginning of the last regulatory control period.
- revised our approach to recognising equity raising costs in 2010-11 consistent with the AER's methodology
- changed our approach to calculating the remaining lives at the beginning of the regulatory control period 2015-20. However, we have not adopted the AER's methodology. Our approach will reduce the depreciation allowance in this period and increase the value of the RAB in 2020 compared to our October Regulatory Proposal. On the other hand, the AER's methodology would have increased the value of the RAB in 2020 to an even higher level. More information on our proposed approach can be found in Section 8.3 below.

The above changes have been made in the following documents:

- Chapter 3 of the Regulatory Proposal
- *03.01.01 – (Revised) Ergon Energy's Building Block Components*
- *03.01.04 – (Revised) Post Tax Revenue Model.*
- *03.01.06 – (Revised) Roll Forward Model.*

We have not updated our proposal to reflect the AER's decision to reduce the value of the RAB for previous investments which provide Alternative Control Services. The AER has mischaracterised Ergon Energy's position in this regard. We stated in our response to the AER that we do not agree

[21] See, for example, Cotton Australia, Op. cit, p8.

[22] Urban Development Institute of Australia Queensland (Cairns Branch) (2015), *Urban Development Institute of Australia Queensland (Cairns Branch) Submission to the AER on Ergon Energy's Regulatory Proposal 2015-2020*, 29 January 2015, p2; and Australians in Retirement – Cairns and District Branch (2015), *A Submission to the AER From the Cairns and District Branch of Australians in Retirement*, 28 January 2015, p2.

with its approach.[23] However, we provided information to assist the AER to make the reductions after we were advised the AER would make its own adjustments if we did not provide updated adjustments. This does not constitute an agreement, which the AER has stated in its Preliminary Determination. We have retained our original position and have not updated our proposal to reflect the AER's Preliminary Determination. However, for completeness, we have included the values that we provided the AER in response to the AER's request for information in our submission response, *SCS Building Blocks, Control Mechanism and Pricing – Response*.

Finally, Ergon Energy notes the AER's position to apply the forecast depreciation approach to establish the opening RAB as at 1 July 2020.

[23] Ergon Energy (2015), *Response to AER Information Request: AER Ergon 060*, 23 February 2015, p2.

6. Rate of return

This section summarises our response to the AER's decision on the rate of return. The allowed rate of return or return on capital enables Ergon Energy to service the cost of funding investments either through debt or equity.

6.1. Preliminary determination

The AER determined an allowed rate of return of 5.85 per cent (nominal vanilla). It was not satisfied that Ergon Energy's proposed rate of return achieves the allowed rate of return objective set out in clause 6.5.2(c) of the NER. The allowed rate of return will be updated annually, to incorporate the annual update of the return on debt estimate.

In reaching this decision, the AER supported our positions on:

- adopting a weighted average of the return on equity and return on debt determined on a nominal vanilla basis
- the risk free rate averaging period for estimating the return on equity
- adopting a 60 per cent gearing ratio
- adopting a 10 year term for the return on debt
- basing forecast inflation on the average of the Reserve Bank of Australia's (RBA) short term inflation rates and the mid-point of the RBA's inflation targeting band.

However, it disagreed with many other aspects of our proposal:

- The AER used the Sharpe-Lintner Capital Asset Pricing Model (SL CAPM) as its foundation model. It was of the view that this model would better achieve the allowed rate of return objective than the multi-model approach proposed by Ergon Energy.[24]
- Relying on its foundation model, the AER also derived estimates which were much lower than what Ergon Energy proposed, including:
  - a risk free rate of 2.55 per cent using a 20 business day averaging period from 9 February 2015 to 6 March 2015. This will be updated for the Substitute Determination based on the averaging period agreed between the AER and Ergon Energy
  - a market risk premium (MRP) of 6.5 per cent. The AER considered a range of 5.1 to 8.6 per cent is reasonable for the MRP, given current market conditions
  - a point estimate of the equity beta of 0.7, consistent with the AER's Guideline.
- The AER used an equal (simple) weighted trailing average approach to estimate the return on debt and, in doing so, rejected Ergon Energy's proposal to base the weighting approach on the debt component of the forecast capital expenditure approved in the PTRM.
- The AER applied a debt risk premium consistent with a BBB+ credit rating, dismissing Ergon Energy's arguments which favoured a BBB credit rating.
- The AER decided to apply an approach to annually updating the trailing average portfolio return on debt using a simple average of the RBA's broad-BBB rated 10 year curve (the RBA curve), and the Bloomberg broad-BBB rated seven year BVAL curve (where available).

[24] Ergon Energy applied all relevant models: the SL CAPM, Black CAPM, Dividend Discount Model and Fama-French model.

The AER's position on the individual Weighted Average Cost of Capital (WACC) parameters is set out in Table 5.

Table 5: AER's Preliminary Determination on Ergon Energy's rate of return

	Ergon Energy's proposal 2015-20	AER preliminary decision 2015-16	AER preliminary decision 2016-20
Return on equity	3.63%	2.55%	2.55%
Equity risk premium	6.87%	4.55%	4.55%
Market risk premium	7.57%	6.50%	6.50%
Equity beta	0.91	0.70	0.70
Nominal post-tax return on equity	10.5%	7.1%	7.1%
Nominal pre-tax return on debt	6.36%	5.01%	Updated annually
Gearing	60%	60%	60%
Nominal vanilla WACC	8.02%	5.85%	Updated annually
Forecast inflation	2.57%	2.55%	2.55%

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 3 – Rate of return*, April 2015, p12.

6.2. Stakeholder feedback

A number of stakeholders, including the CCP, stated the allowed rate of return proposed by Ergon Energy is too high.[25] Stakeholders suggested this is because our proposed rate of return did not reflect the declining real interest rates since the 2010-15 Distribution Determination, the market outlook or the nature of our business.[26] Alternative allowed rates of return in the range of 3.6 per cent[27] to 7 per cent[28] were recommended.

At the public forum held on 9 December 2014, the CCP also highlighted consumer concerns that a rate of return determined in accordance with the Guideline would result in excessive profits.[29]

Some stakeholder submissions also contained specific comments on the return on equity. For example:

- The Chamber of Commerce and Industry Queensland recommended the adoption of an equity beta lower than 0.7, a low MRP in the range of 5 to 7.5 per cent, and the setting of the risk free rate over a term shorter than 10 years. [30]
- The Alliance of Electricity Consumers suggested SFG's finding on the equity beta are overly generous to Ergon Energy and should be lower to reflect Ergon Energy's lack of systemic risk

[25] See, for example, Darling Downs Cotton Growers Inc, Op. cit, p2; Cotton Australia, Op. cit, p11; Canegrowers Isis Ltd, Op. cit, pp2-3; Australians in Retirement, Op.cit, pp2-3; Far North Queensland Regional Organisation of Councils (2015), *AER Issues Paper, Queensland Electricity Distribution Regulatory Proposals 2015-16 to 2019-20,* 30 January 2015, p4; Chamber of Commerce and Industry Queensland, Op. cit, pp16-20; COTA Queensland (2015), *Ergon Energy Regulatory Proposal 2015-20,* 30 January 2015, p2; and Urban Development Institute of Australia Queensland (Cairns Branch), Op. cit, p2; Hugh Grant (CCP member) (2014), *Preliminary Perspectives: Energex and Ergon Revenue Proposal*, Presentation at the AER Public Forum, 9 December 2014; and Regional Development Australia Far North Queensland and Torres Strait Inc (2015), *RE: Qld electricity distribution regulatory proposals 2015/16 – 2019/20*, 30 January 2015, p3.
[26] See for example, Canegrowers Isis Ltd (2015), Op. cit, pp2-3.
[27] Bundaberg Regional Irrigators Group, Op. cit, p3.
[28] Cotton Australia, Op. cit, p11.
[29] Hugh Grant, Op. cit.
[30] Chamber of Commerce and Industry Queensland, Op. cit, pp16-20.

under the revenue cap. It also stated the MRP does not align with equity expectations of other Queensland Government Owned Corporations and inflates our expected returns.[31]

- The Queensland Council of Social Service (QCOSS) supported the use of the SL CAPM model, on the basis that it is reasonably predictable and transparent, and reduces opportunities for cherry-picking. However, it proposed a downwards adjustment to the SL CAPM to cater to the upwards bias in the SL CAPM for low beta stocks. QCOSS also recommended an equity beta of between 0.5 and 0.6 and a MRP of 6 per cent.[32]

Some stakeholders questioned Ergon Energy's proposal to use a BBB credit rating to estimate the return on debt, on the basis that Ergon Energy is a low risk organisation.[33] The Darling Downs Cotton Growers Inc and Central Highland Cotton Growers and Irrigators Association requested the AER to examine this rating and several other stakeholders, including QCOSS and the Queensland Farmers' Federation, suggested higher credit ratings.[34]

QCOSS also submitted that the AER should use a five year BBB+ rate, rather than a 10 year rate. It stated, among others, that this rate reflects other regulators' decisions and is a more realistic debt setting period in capital markets in Australia.[35] QCOSS also supported the AER's use of a simple weighted average approach.[36]

6.3. Other influencing factors

At the time of submitting our October Regulatory Proposal, we were optimistic that the market parameters around the cost of capital would continue to improve relative to the assumptions in our proposal, delivering even better outcomes for customers in terms of what we ultimately charge.

To some extent this has occurred. Our revised Regulatory Proposal therefore reflects a fall in the expected cost of equity and debt based on the most recent market conditions. The AER has written to Ergon Energy noting that it will update the expected cost of equity using an averaging period closer to the time of the Substitute Determination. In order to assist the AER, we will provide updated information to allow the AER to calculate the rate of return using Ergon Energy's preferred methodology. We will apply a similar period to the AER's observed period.

Ergon Energy has considered relevant decisions made by the AER and new expert evidence since our October Regulatory Proposal. Ergon Energy made a number of submissions to the AER on other NSP processes as many of the issues raised in these determinations were of relevance to the AER's determination for Ergon Energy. We have also had regard to the regulatory proposals submitted by Victorian Distribution Network Service Providers (DNSPs) on 30 April 2015.

In respect of the AER's recent decision on the cost of debt for NSW and the ACT, we note that the AER has slightly altered its stance with regard to the efficient debt management strategy for the benchmark entity. We have considered this when reviewing our expected rate of return for the regulatory control period 2015-20.

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[31] Alliance of Electricity Consumers (2015), *Submission on Ergon Energy's Regulatory Proposal 2015-2020,* 30 January 2015, p26.
[32] QCOSS, Op. cit, pp76-79.
[33] Darling Downs Cotton Growers Inc, Op. cit, p2; Chamber of Commerce and Industry Queensland, Op. cit, pp16-20; and Australians in Retirement – Cairns and District Branch, Op. cit, p2.
[34] QCOSS, Op. cit, p76; Queensland Farmers' Federation (2015), *Submission to the Australian Energy Regulator (AER) on the Ergon Energy and Energex Regulatory Proposals for 2015-20,* 30 January 2015, p11; and Central Highlands Cotton Growers and Irrigators Association (nd), *RE: QLD Electricity Distribution Regulatory Proposals 2015-2020,* p3.
[35] QCOSS, Op. cit, p79.
[36] QCOSS, Op. cit, p80.

6.4. Our response

Our approach to estimating the expected return on equity has not changed from our October Regulatory Proposal and continues to differ from the AER's. Estimating the return on equity must take into account all relevant evidence, and where that evidence is probative as to the required return on equity, it must be given a direct role in the estimation process. The AER's approach does not do this. Rather, it relies on its foundation model both to set the rate of return and to justify its rejection of other approaches. This is despite recent changes that were made to the NER with the explicit intention of allowing other evidence and models to be considered.

We have revised our Regulatory Proposal to reflect more up-to-date market information. We have also included additional evidence in support of the necessary move away from the sole or predominant reliance on the SL CAPM when setting our allowed rate of return for equity. There is extensive support for the use of each of the dividend growth model/dividend cash flow, Black CAPM and Fama-French Three Factor Model *concurrently* with the SL CAPM.

In respect to the cost of debt, we note that many aspects of the AER's Preliminary Determination are consistent with our October Regulatory Proposal. However, we disagree with the AER's decision to:

- adopt a simple weighted trailing average approach
- apply a transition to the debt risk premium
- apply a BBB+ credit rating.

Further, we have made some changes to reflect the AER's recent decisions for NSW and the ACT. We are now proposing a cost of debt that reflects:

- the average of the 1-10 year swap rates (in place of the average 10 year swap rate in our October Regulatory Proposal)
- the weighted trailing average swap risk premium using a hybrid approach
- the cost of the swap transactions required to effect the transition.

Appendix C of our revised Regulatory Proposal outlines the evidence base to our response to the AER's Preliminary Determination, including evidence supporting changes to the rate of return inputs. The full suite of expert evidence is provided in the following supporting submissions:

- *Rate of Return (Cost of Equity) Response*
- *Rate of Return (Cost of Debt) Response.*

6.5. Equity and debt raising costs

6.5.1. Preliminary Determination

Equity raising costs

The AER did not include an allowance for equity raising costs on the basis that our October Regulatory Proposal did not include any equity raising costs. Section J.1 of Attachment 3 of the Preliminary Determination states:

"Ergon Energy did not propose equity raising costs in its regulatory proposal. Therefore, we do not provide an allowance for equity raising costs in the 2014-19 regulatory control period."[37]

Debt raising costs

Ergon Energy proposed a debt raising allowance of $66.7 million over the five year period to compensate for the transactional costs that a prudent service provider acting efficiently incurs while raising debt.

The AER accepted our debt raising costs of $28.2 million and our method for determining debt raising transaction costs in relation to funding the RAB, but it did not accept our proposed total debt raising cost forecast. This is because the AER:

- amended our debt raising transaction costs, in light of changes it made to our opening RAB, projected RAB and allowed rate of return
- removed our proposed liquidity costs from our benchmark rate of debt raising costs
- removed costs associated with three month ahead financing.

6.5.2. Our response

Our detailed response to the AER's Preliminary Determination is found in our supporting submission *SCS Building Blocks, Control Mechanism and Pricing – Response*.

Ergon Energy notes that our October Regulatory Proposal makes numerous references to equity raising costs:

- Our RIN response included the allowance for equity raising costs in table 2.1.1.
- Our regulatory model architecture summary notes that we include modelling for equity raising costs as part of our ARR.
- Our regulatory models include the recovery of equity raising costs.

Consistent with our October Regulatory Proposal, Ergon Energy has proposed equity raising costs in our revised Regulatory Proposal. They are also explicitly set out in Appendix C of our revised Regulatory Proposal. Equity raising costs have been included in the forecast capital expenditure in 2015-16 and have been calculated using the methodology embodied within the AER's PTRM.

We have not revised our proposal in line with the AER's Preliminary Determination on debt raising costs. The AER's considerations are insufficient to justify a departure from Ergon Energy's approach. The proposed liquidity costs and three month ahead financing costs are legitimate expenses that would be incurred by the benchmark efficient firm in raising debt and should be compensated through the operating expenditure allowance.

[37] AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 3 – Rate of return*, April 2015, p482.

7. Value of imputation credits (gamma)

This section summarises our response to the AER's decision on gamma.

7.1. Preliminary Determination

The AER did not accept our proposed value of imputation credits of 0.25, instead adopting a value of 0.4. This value was selected from within a range of 0.3 – 0.5.

The AER departed from its Guideline in deriving the value of imputation credits, citing new evidence and advice.

In our October Regulatory Proposal and the Preliminary Determination, gamma was calculated by multiplying the estimate of the distribution rate and utilisation rate. We continue to adopt this definition in our revised Regulatory Proposal.

7.1.1. Distribution rate

The AER used an estimate of 0.8 for the distribution rate when considering estimates of the utilisation rate that relate to listed equity only, and an estimate of 0.7 when considering estimates of the utilisation rate that relate to all equity.

It estimated the distribution rate using the 'cumulative payout ratio approach', which uses data from the Australian Tax Office (ATO) on the accounts used by companies to track their stocks of imputation credits.

7.1.2. Utilisation rate

The AER rejected our proposed utilisation rate (theta) of 0.35. The AER placed significant reliance of the 'equity ownership approach' to estimate the utilisation rate consistent with its Guideline. Under this approach, the AER considers a reasonable estimate for the utilisation rate is:

- 0.56 and 0.68, if all equity is considered, and
- 0.38 and 0.55, if only listed equity is considered.

It also had regard to tax statistics, which suggested an estimate of the utilisation rate in the range of 0.4 and 0.6. The AER noted evidence from the expert report of Professor Gray and Dr Hall, which suggested that the utilisation rate was 0.35 and that evidence from other market studies suggested the utilisation rate could be higher or lower than 0.35.

The AER did not agree with our adoption of a market-based approach. The AER stated the equity ownership approach and tax statistics provide more direct and simpler evidence of the utilisation rate, and identified a number of limitations with the implied market value studies.

The AER departed from its Guideline in terms of the data used in determining the utilisation rate. It has re-examined the National Accounts data relating to the percentage of Australian equity held by domestic investors. Specifically, it has focused on the types of equity that it considers are most relevant to a benchmark entity, and the specific classes of investor that are expected to either utilise or waste the imputation credits they receive.

7.2. Stakeholder feedback

QCOSS suggested a gamma value of 0.5, consistent with the Guideline.[38]

7.3. Our response

Ergon Energy maintains that a value of imputation credits should be a market value and that 0.25 is the most appropriate value at this time.

Value of Imputation Credits – Response provides our detailed response to the issues raised by the AER, including the reasons why we have not updated our proposal to reflect the gamma determined by the AER. We have provided additional material in support of our response to the AER's preliminary decision and this is outlined in our response.

While we have not changed our position to what we proposed in October 2014, we have revised our Regulatory Proposal to reflect the new evidence that has been provided since October 2014 which provides clear guidance for the AER, when revoking and substituting the Substitute Determination in place of the Preliminary Determination, to replace the gamma of 0.4 with a value of no more than 0.25.

[38] QCOSS, Op. cit, p81.

8. Regulatory depreciation

This section summarises our response to the AER's decision on regulatory depreciation, which allows Ergon Energy to recover our investment over the economic life of the asset.

8.1. Preliminary Determination

The AER did not accept our proposed regulatory depreciation allowance of $903.94 million for the regulatory control period 2015-20. It determined an allowance of $654.6 million.

8.1.1. Depreciation approach

The AER supported our proposed straight-line depreciation method to determine the regulatory depreciation allowance set out in the PTRM and the proposed standard asset lives. However, it rejected our proposal to use the proposed average depreciation method to calculate the remaining asset lives as at 1 July 2015.

8.1.2. Standard asset lives

The AER accepted our proposed standard asset lives for our existing asset classes. The standard asset lives were the same as those approved by the AER for the regulatory control period 2010-15. However, it updated the standard asset life for the 'Equity raising costs' asset class to reflect changes it made to the opening RAB. The AER applied the same weighted average approach to determining the standard asset life as approved for the regulatory control period 2010-15.

8.1.3. Remaining asset lives

The AER did not accept our proposed average depreciation approach to calculating the remaining asset lives as at 1 July 2015. Instead, the AER used the weighted average remaining life (WARL) approach. The AER believes its approach results in remaining asset lives that better reflect the nature of the assets over their economic lives. Further, this approach is consistent with the approach taken by other service providers.

8.2. Stakeholder feedback and other influencing factors

There has been no stakeholder feedback received on regulatory depreciation. However, we noted above there have been strong stakeholder concerns regarding the high RAB value. In reviewing the AER's decision on depreciation approach, we have also reviewed depreciation approaches taken by other NSPs.

8.3. Our response

The AER's Issues Paper to our Regulatory Proposal noted that Ergon Energy's RAB increased by around 27 per cent. In the Issues Paper, the AER stated it will investigate why the RABs are proposed to continue to grow so significantly.[39] Ergon Energy noted in our response to the AER's Issues Paper that the regulatory framework is a key contributor to increasing RAB values.[40] In effect,

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[39] AER (2014), *Issues paper, Qld electricity distribution regulatory proposals 2015–16 to 2019–20*, December 2014, p19.
[40] Ergon Energy (2015), *Submission on the Queensland electricity distribution regulatory proposals 2015–16 to 2019–20 Issues Paper*, 30 January 2015, p4.

the indexation of the RAB is a deferral of returns back to Ergon Energy from our investment. This has the effect of deferring revenue recovery from the current period and into future periods through inflating the RAB.

Ergon Energy's approach to calculating remaining lives for assets at the beginning of the period is consistent with the approach approved by the AER in 2010. The AER's decision to reject Ergon Energy's methodology in favour of another approach has the effect of inflating the RAB at the end of the period.

In support of this approach, the AER provided analysis which indicated that, compared to the AER's preferred methodology of calculating remaining lives, Ergon Energy's approach increases the annual depreciation allowance and returns the value of the asset quicker.[41] The AER's argument is that an approach that under-estimates the remaining lives of the assets results in assets being fully depreciated before the end of their useful lives. In turn, this may encourage inefficient use and early replacement of assets inconsistent with the NEL.

We have attempted to replicate the AER's analysis and note that it does not appear to consider other impacts on the RAB roll-forward – namely the CPI indexation – when considering the impact on the depreciation profile of assets. Ergon Energy believes this regulatory arrangement over-estimates the remaining lives of assets and has the risk of assets not being fully depreciated until after the end of their useful lives.

When combined with a WARL approach to a mixture of old and new assets in an asset class, the likelihood of residual asset values remaining in the RAB past their economic life is even greater. The result is an increased risk of future generations paying more as they are paying for assets that have since been replaced.

It is important to note that the return of the asset is Net Present Value (NPV) neutral. Customers do not pay more or less in NPV terms under either approach. Nevertheless, we consider the AER approach has a tendency to inflate the RAB more than necessary and this is something our customers do not want.

We provide more information supporting this in our supporting submission *SCS Building Blocks, Control Mechanism and Pricing – Response.*

Notwithstanding our concerns that the AER's proposed direction may not be in the long term interests of customers when a broader range of factors are taken into account, Ergon Energy has revised our proposal to be more consistent with other NSPs and their approach to remaining lives.

Our revised approach is outlined in our revised Regulatory Proposal and in section 4.2.2 of the supporting document *03.03.01 – (Revised) Building Block Components*. We also rely on additional evidence from Houston Kemp who have provided advice on alternative approaches to calculating the remaining life.

[41] AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 5 – Regulatory depreciation*, April 2015, p14.

9. Capital expenditure

This section summarises our response to the AER's decision on our capital expenditure allowance. Capital expenditure is distinguished between two types of capital expenditure – network and non-network.[42] The components of our capital expenditure requirement include:

- augmentation expenditure[43]
- customer connections expenditure[44]
- replacement expenditure[45]
- non-network capital expenditure.[46]

9.1. Preliminary determination

The AER did not accept our proposed total capital expenditure allowance of $3,397 million for the regulatory control period 2015-20. It stated that our proposal did not reasonably reflect the capital expenditure criteria set out in clause 6.5.7(c) of the NER. Instead, the AER determined a total capital expenditure allowance of $2,182 million. As illustrated in Table 6, this is a reduction of 36 per cent.

Table 6: AER's preliminary determination on Ergon Energy's total forecast capital expenditure, 2015-20

$m (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Ergon Energy's proposal	739.8	723.2	659.4	644.5	630.0	**3,397.0**
AER Preliminary Determination	540.1	495.3	428.1	381.0	337.5	**2,182.0**
Difference	(199.7)	(227.9)	(231.3)	(263.5)	(292.6)	**(1,215.0)**
Percentage difference	(27%)	(32%)	(35%)	(41%)	(46%)	(36%)

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 6 – Capital expenditure*, April 2015, p8.

Table 7 provides the capital expenditure amounts, by each capital expenditure driver, that were included in the AER's alternative estimate. The AER's assessment of these drivers and our forecasting methodology is summarised below.

[42] Our proposal refers to these types of expenditure as 'system' and 'non-system' capital expenditure.
[43] This encompasses our 'Corporation initiated augmentation', 'Reliability and quality of supply' and 'Other system' categories of capital expenditure.
[44] Our proposal refers to this category of expenditure as 'Customer connection initiated capital works'.
[45] Our proposal refers to this category of expenditure as 'Asset renewal capital expenditure'.
[46] Our proposal refers to this category of expenditure as 'Non-system capital expenditure'.

Table 7: AER's assessment of Ergon Energy's required capital expenditure (by driver), 2015-20

$m (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Augmentation	133.5	126.3	117.6	91.6	90.0	**559.0**
Connections	85.2	86.3	87.6	88.8	90.0	**437.8**
Replacement	131.3	146.0	125.4	137.1	134.8	**674.6**
Metering	1.4	1.4	1.4	1.4	1.4	**7.0**
Non-network	112.7	90.5	80.0	71.7	65.4	**420.3**
Capitalised overheads	197.3	194.4	189.9	193.0	187.2	**961.8**
Materials escalation adjustment	(91.5)	(119.3)	(141.8)	(169.7)	(197.9)	**(720.3)**
Gross capital expenditure (incl. capital contributions)	**569.9**	**525.7**	**460.0**	**413.8**	**370.9**	**2,340.3**
Less Capital contributions SCS	29.8	30.4	31.9	32.9	33.4	**158.3**
Net capital expenditure (excl. capital contributions)	**540.1**	**495.3**	**428.1**	**381.0**	**337.5**	**2,182.0**

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 6 – Capital expenditure*, April 2015, p19.

9.2. Forecasting methodology

9.2.1. Preliminary Determination

The AER was not satisfied with our forecasting methodology due to:

- our reliance on using bottom-up assessments to forecast expenditure
- our approach to risk assessment in our cost-benefit analysis of capital projects and programs.

Insufficient top-down restraint

The AER stated that applying a bottom-up build is unlikely to result in a total forecast capital allowance that reasonably reflects the capital expenditure criteria. This is because this approach tends to overstate required capital allowances, as it does not appropriately consider interrelationships and synergies between projects or areas of work. The AER therefore considers a top-down assessment is required.

While Ergon Energy employed a top-down assessment, the AER and its consultant, EMCa, did not consider our approach "brings sufficient restraint to bear on the overall forecast".[47] In particular, EMCa indicated that our forecast "is not reasonable and exhibits a degree of upwards bias that reflects cost and risk over-estimation and the application of a CPI-based price objective as its primary top-down challenge constraint".[48]

[47] AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 6 – Capital expenditure*, April 2015, p23.
[48] EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon's Regulatory Proposal 2015-2020*, piv.

Lack of cost-benefit analysis

The AER stated that our cost-benefit evaluation shows our underlying risk assessment is excessively conservative, resulting in forecast capital expenditure greater than is necessary to achieve the capital expenditure objectives. The AER considers the preferred tool for most risk assessments is a cost-benefit analysis; not the 'As Low As Reasonably Practical' (ALARP) principle.

9.2.2. Our response

Insufficient top-down restraint

The AER concludes that Ergon Energy's forecasting methodology predominately relies upon a bottom-up build (or bottom-up assessment) to estimate the forecast expenditure and that the top-down constraints imposed by Ergon Energy's governance process are insufficient for the AER to be able to conclude that the forecasts are prudent and efficient.

Despite reaching this conclusion, the AER in fact accepted over 80 per cent[49] of the forecast capital expenditure proposed by Ergon Energy, accepting in full the proposed forecasts for various safety driven Asset Renewal programs and accepting in full the following capital expenditure categories (after allowing for the escalations error and reductions in other escalators or overheads):

- customer connections
- quality of supply
- reliability
- minor property programs.

In reaching the above conclusion, the AER appears to have also not expressly considered a number of key supporting attachments supplied by Ergon Energy as part of our Regulatory Proposal regarding our use of top-down and bottom-up forecasting processes (including *06.01.05 – Meeting Rules Requirements for Expenditure Forecasts* (Meeting the Rules Requirements supporting document)).

Instead, the AER has relied very heavily on the report of its consultant, EMCa, and, in particular, EMCa's incorrectly drawn conclusion that Ergon Energy's governance process to challenge and review our capital expenditure forecasts was driven to achieve a CPI-based objective and/or "meet capex expectations following AER review" rather than being driven to derive capital expenditure forecasts that complied with NER requirements.

Both EMCa and the AER seem to have reached this conclusion without in any way referencing, citing or considering the key Meeting the Rules Requirements supporting document mentioned above or considering other material supplied by Ergon Energy, including power point slides and Q&A responses that as a whole, demonstrates Ergon Energy's adherence to the NER objectives, criteria and factors.

Ergon Energy identified the potential for dot points on power point slides and other material to be misconstrued or quoted selectively at the time the material was disclosed to the AER and EMCa. Accordingly, Ergon Energy invited the AER and/or EMCa to seek further context surrounding the deliberations undertaken. Neither the AER nor EMCa sought to engage with Ergon Energy on this particular aspect before the EMCa report was released or before the AER's Preliminary Determination was issued.

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[49] After adjustment for the $600 million escalations error conceded by the AER.

In particular, Ergon Energy notes the suggestion by EMCa that:

> "Evidence provided by Ergon indicates that the top-down challenge process was driven to achieve a CPI-based price objective … and that we consider that a CPI-based price objective does not provide a meaningful discipline that would lead Ergon to a prudent and efficient capex level, consistent with the NER expenditure criteria" …

is not supported on a proper reading of the Board and AER Forecast Review Committee slide packs disclosed to EMCa, the information Ergon Energy officers supplied to the AER or EMCa at the on-site meetings held in 2015 and/or from the material provided in our Regulatory Proposal, itself.

EMCa appears to have accepted the possibility that "Ergon's objective of delivering services at the best possible price could be construed as a cost forecasting discipline, consistent with the prudency and efficiency criteria" (para 59) but for reasons that are unclear discount this possibility further by selectively quoting from and misconstruing various documents, as well as apparently simply ignoring others.

Had the AER and EMCa properly and fully considered the Meeting the Rules Requirement supporting document, the AER and EMCa would have seen a clear outline of the various NER requirements and considerations balanced in the company's deliberations including Ergon Energy's consideration of achieving efficient pricing of capital inputs. Unfortunately, EMCa appears to have not expressly referenced or considered this critical document in their report despite Ergon Energy officers repeatedly drawing EMCa's attention to this document on multiple occasions, and despite accepting various top-down benchmarking reports and material as evidence that Ergon Energy's capital expenditure unit costs were at benchmarked levels and cost estimate processes were reasonable and did not contain upward bias.

EMCa reach the following conclusions in para 65 of the report:

> "We note that presentations provided by Ergon include strategic environmental scans of the RP's for other regulated agencies,[33] lower expenditure scenarios as illustrated in Figure 8 below,[34] and "fall back"[35] positions on regulatory proposals with some anticipation of "AER reductions".[36] This process may suggest that a level of conservatism and potential contingency is built into the proposed expenditure allowance, with capex constrained not to an optimal level, but rather strategically positioned to meet capex expenditure expectations following AER review and price path objectives, as described above."

The above analysis by EMCa appears to be based on a limited reading of various slides and working papers disclosed by Ergon Energy, failure to recognise scenario analysis and environmental scanning is a feature of all standard business and strategy planning processes undertaken by most modern companies and also does not recognise the exact timing and content within the forecasting process underway at which the material had been produced (e.g. was it prepared early in deliberations or after more detailed consideration of various risks and options etc.).

Ergon Energy can find no evidence to support the above-mentioned EMCa findings in our internal records, the slide packs that have been disclosed or our Regulatory Proposal itself.

The slide that mentions "fall back" positions, for example, clearly outlines a number of total expenditure reduction options being considered by Ergon Energy – none of which were linked to or constrained by a CPI-based price objective. As it transpired, the so-called "fall-back" and higher total expenditure scenario was not accepted by the company as the foundation for our Regulatory Proposal and the "preferred" scenario proposed by Ergon Energy's Chief Executive Officer (CEO) in March 2014 ended up being in fact the scenario the company based our total expenditure on – that is, 'pull it [totex] down' in 2010-15 and 'keep it down' in 2015-20.

In contrast to the analysis by EMCa regarding the impact of CPI-based price paths on unduly constraining the company's process, we also draw the AER and EMCa's attention to the CEO's comments in the Overview Document:

> "Of course, we know it is not all about price. We appreciate that our customers value the peace of mind they receive from a safe and dependable service, and that they also increasingly want greater choice and control in their energy supply solutions. It's about getting the balance right.
>
> This has been at the centre of our discussions with our customers throughout the preparation of our Regulatory Proposal"

Appendix A (confidential) provides an example highlighting the range of considerations that informed the company's approach – including but not limited to CPI-X thinking on price and reductions in total expenditure.

Similarly, the selective analysis undertaken by EMCa has meant that EMCa also reached incorrect conclusions regarding the progressive variations made to various system capital expenditure direct cost forecasts supplied to EMCa by Ergon Energy. This material included some examples of the iterative governance processes adopted by the company in developing our capital expenditure forecasts (see in particular paragraphs 64-67 and Figure 8 of the EMCa report).

For example, EMCa claim Figure 8 of their report (which contains a point in time update of the variations being made to Ergon Energy's forecasts and does not represent Ergon Energy's final forecasts included in our October Regulatory Proposal) is an example where "scenarios for further cuts in asset renewal expenditure below the RP…appear to be untested for 'similar' cost savings". It should be noted that the graph in Figure 8 relates to a single step in the company's governance process (that is, version 3 of the system capital expenditure review process from Figure 7) and was undertaken by management and relevant subject matter experts to understand the sensitivities to network risk and asset management strategies by assuming scenarios of reduced expenditure at the total system capital expenditure portfolio level. This was one of a number of ways that the company tested the prudency and efficiency of our forecast capital expenditure.

As EMCa was made aware, and as demonstrated in the Q&A and other supporting material made available to the AER and EMCa, Ergon Energy's governance process continued to challenge and refine forecast expenditure with further reductions being provided in versions 4 to 8 of the capital expenditure review process depicted in Figure 7. The final system capital expenditure forecast adopted in Ergon Energy's October Regulatory Proposal was also in fact lower than the expenditure depicted in Figure 8.

Lack of cost-benefit analysis

From an Asset Renewal perspective, Ergon Energy generally manages risks according to the ALARP principle. The exception to this is when the risks relate to electrical safety, in which case we must apply the "So Far As Is Reasonably Practical" (SFAIRP) principle. It appears EMCa has incorrectly assumed that the ALARP principle applies when managing all risks and does not fully consider the relevant legal and common law tests applicable to maintaining safety as indicated in previous material submitted to the AER and EMCa. Further, discussion of this aspect appears in the *Asset Renewal Capital Expenditure – Response (Asset Renewal Response)*, along with various concerns as to how the AER has itself assessed risk in approving or rejecting various sub-component forecasts of Asset Renewal expenditure proposed by Ergon Energy.

9.3. Capital expenditure performance and trend

9.3.1. Preliminary Determination

Benchmarking

The AER examined Ergon Energy's capital expenditure performance on a number of metrics against other DNSPs in the National Electricity Market (NEM). However, it did not use this information deterministically in its assessment. The AER found:

- Ergon Energy performed relatively poorly on a range of partial productivity of capital and multilateral total factor productivity measures.
- Ergon Energy's capital expenditure per customer was and is forecast to be among the highest in the NEM.
- Ergon Energy's capital expenditure per maximum demand was among the highest in the NEM, but is forecast to reduce in the regulatory control period 2015-20.

Trend analysis

The AER examined Ergon Energy's forecast capital expenditure against the long term trend in capital expenditure levels (2001 to 2012). The AER found Ergon Energy's average proposed capital expenditure for the regulatory control period 2015-20 is similar to the previous period. However, it is substantially more than expenditure in the early 2000s.

9.3.2. Our response

Our October Regulatory Proposal reported expenditure for the regulatory control period 2010-15 based on audited information for all historical expenditure and an estimate of expected expenditure for the 2014-15 year. For all relevant expenditure categories we have reviewed and, where appropriate, updated the estimate in the October Regulatory Proposal for the 2014-15 year.

Our supporting submission, *System Capex Financial Performance 2014-15,* provides an update of this estimated system capital expenditure relating specifically to the 2014-15 financial year and offers an explanation for changes. Updates for 2014-15 expenditure for non-system capital expenditure have been reflected in the relevant supporting documents.

The latest estimates for 2014-15 have been incorporated in our capital expenditure modelling.

9.4. Augmentation expenditure

9.4.1. Preliminary Determination

The AER substituted our forecast augmentation expenditure allowance of $660 million with its own value of $558.1 million (excluding overheads). This is a reduction of 15.5 per cent. In arriving at this alternative estimate, the AER:

- removed the impact of the overestimation bias it considers to be evident in our forecast distribution and sub-transmission capital expenditure. The AER used the mid-point of the range determined through the EMCa's technical review of a sample of projects
- removed the impact of the overestimation bias it considers to be evident in our forecast other system-enabling capital expenditure. The AER applied the upper range determined by EMCa's distribution and sub-transmission forecasts
- removed the unexplained capital expenditure forecast.

Trend analysis

The AER noted our forecast capital expenditure for each driver decreased compared to the actual capital expenditure in the regulatory control period 2010-15, particularly for reliability and other augmentation.

The AER identified our demand-related augmentation expenditure as the largest component of our augmentation expenditure proposal. Therefore, it assessed trends in maximum demand and network utilisation. It found:

- Evidence suggests low demand growth over the regulatory control period 2015-20.
- There has been declining demand in the regulatory control period 2010-15.
- There was a small decline in network utilisation between 2009-10 and 2013-14, consistent with declining demand during this period and changes made to our design standards following the 2011 Electricity Network Capital Program Review.
- The forecast zone substation utilisation for the regulatory control period 2015-20 shows the majority of our substations are not forecast to be heavily utilised by 2020 and the number of highly utilised substations is forecast to decline. However, there are a number of highly utilised substations that may need to be augmented during this period. This suggests that some level of network augmentation is required.

Forecasting methodology

EMCa found that our framework and methodology is consistent with industry standards and the top-down assessment process applied by Ergon Energy delivered material reductions in our initial bottom-up forecast. However, there was concern that applying the top-down assessment to meet a price path objective may result in an overstated forecast.

In assessing our governance and forecasting methodology, the AER focused on the factors discussed below.

Demand forecasting

The AER was satisfied that our augmentation expenditure forecast is based on a realistic expectation of demand. However, it expects Ergon Energy's revised Regulatory Proposal to take into account the Australian Energy Market Operator's (AEMO) connection point demand forecasts for Queensland. This is discussed further in Section 9.10 below.

Cost estimation

The AER stated that our cost estimation methodology is sound. However, during the sampling review, there was evidence the scope and design of some projects led to a total forecast that is higher than is necessary for a prudent and efficient DNSP.

Governance and top-down constraints

EMCa concluded that our internal governance and committee structure, which employs a top-down constraint on bottom-up projects forecasts, led to material reductions in our proposed forecast augmentation expenditure (compared to forecasts prepared in earlier planning processes).

The AER suggested that our proposal to limit network price growth was also a top-down constraint on our capital expenditure. The AER considers there is no evidence to prove that this results in prudent and efficient capital expenditure. Further, it may lead to overestimation. We have addressed the AER's errors in forming this view earlier in this submission (see Section 9.2.2).

Driver and project analysis (subtransmission and distribution)

The AER engaged EMCa to undertake a technical review of a sample of projects. This review focused on our distribution, sub-transmission, and reliability and quality of supply capital expenditure forecasts. EMCa found that we used a robust methodology to estimate the cost of augmentation. However, they also identified systemic issues of overestimation in the sampled projects.

Specifically, EMCa's findings indicated that our augmentation expenditure:

- is not always adequately linked to a prudent needs-driven analysis, including efficient timing of expenditure and connection of new load
- is not always adequately supported by cost-benefit analysis, robust options analysis and appropriately applied risk-assessment
- includes some estimates that have led to a higher level of expenditure than may be required.

EMCa concluded that:

- our sub-transmission proposal was overestimated by 0 to 5 per cent. Consequently, the AER applied a 2.5 per cent reduction to our forecast.
- our distribution proposal was overestimated by 10 to 20 per cent. Consequently, the AER applied a 15 per cent reduction to our forecast.

Power quality, reliability and other system capex

In addition to the above, the AER:

- accepted our proposed power quality and reliability forecast, based on EMCa's findings and the AER's comparison against historic expenditure
- considered the systemic biases in the sub-transmission and distribution forecasts are likely to also be present for other system-enabling capital expenditure. It therefore reduced our forecast by 15 per cent.
- was unable to account for $33 million of expenditure in its analysis, so reduced this amount from the allowed forecast.

9.4.2. Stakeholder feedback

Many stakeholders expressed dissatisfaction with the amount of augmentation expenditure requested, particularly in a falling demand environment.[50] Some stakeholders sought substantial cuts to the augmentation program,[51] while others wanted more justification.[52] The Total Environment Centre also expressed doubts regarding the network impacts of solar PV raised by Ergon Energy.[53]

9.4.3. Other influencing factors

Our response to the AER's Preliminary Determination and stakeholder feedback has been driven by a number of additional factors:

- We have a better understanding of what we are likely to spend in 2014-15 for this category of expenditure and how it affects our estimates.
- We have updated demand forecasts for the period.
- We have taken into account possible changes in government policy which may impact the future.
- We have reviewed our subtransmission network program of works in the context of changes to the Value of Customer Reliability (VCR).

9.4.4. Our response

We have considered new information, as outlined in Section 9.4.3. Where appropriate, we have incorporated this information in our revised Regulatory Proposal. As a result, the following documents have been updated:

- Appendix B of our Regulatory Proposal
- *07.00.02 – (Revised) CIA Expenditure Forecast Summary*
- *07.00.04 – (Revised) Other Systems & Enabling Technologies Summary*
- *07.00.05 – (Revised) Reliability & Quality of Supply Summary*
- *07.02.02 – (Revised) Distribution Network Augmentation Plan.*

Ergon Energy generally does not accept the AER's Preliminary Determination on augmentation expenditure. As such, we have not made revisions to the October Regulatory Proposal to reflect all aspects of the AER's decision. A summary of concerns in relation to the AER's Preliminary Determination is below.

Our detailed submission on augmentation expenditure is contained in *Corporation Initiated Augmentation Capital Expenditure – Response (CIA Response)*. This document details our response on the issues raised by the AER, its consultant and stakeholders, including the reasons why we have not updated our proposal to reflect all aspects of the Preliminary Determination. It also sets out the changes Ergon Energy has made in our revised Regulatory Proposal.

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[50] Cotton Australia, Op. cit, p7; Chamber of Commerce and Industry Queensland, Op. cit, p11; Alliance of Electricity Consumers, Op.cit, pp10-12; Canegrowers, Op. cit, p5; COTA Queensland, Op. cit, p2; and Australian PV Institute (2014), *APVI Submission to the AER on the Issues Paper on Ergon's and Energex's Network's Regulatory Proposals December 2014*, p3.

[51] Alliance of Electricity Consumers, Op. cit, pp10-12.

[52] QCOSS, Op. cit, p42.

[53] Total Environment Centre (2015), *Submission to the AER on Queensland distribution networks' 2015-20 revenue proposals*, February 2105, p16.

Driver and project analysis

Sub-transmission program

There has been no reasoning provided in the Preliminary Determination or new evidence or material which would justify a departure from the original list of subtransmission projects and level of overall subtransmission expenditure included in our October Regulatory Proposal.

The AER reduced the subtransmission forecast by 2.5 per cent based on its consultant's advice that "there are opportunities for Ergon Energy to optimise its sub-transmission programs, including project deferral, greater tolerance of risk and the timing of capex. Based on these findings, EMCa considered that Ergon Energy's proposal is overestimated by 0 to 5 per cent".[54] There is no clear evidence pointing toward the top or bottom of the range provided by EMCa.

Ergon Energy maintains the subtransmission augmentation program has been developed optimally to reflect the timing of constraints on the network and to ensure the lowest overall cost option has been selected to resolve network constraints. The change from deterministic to probabilistic planning during the regulatory control period 2010-15 has been reflected in the development of options. We have also taken into consideration the optimal balance between non-network and network based solutions, including demand management and operational responses to meet the requirements of the new security of supply criteria defined within our distribution licence conditions.

The level of risk tolerance at the subtransmission level is defined by clear parameters within the security of supply standards, NER, Queensland legislation and Australian Standards. In developing our Regulatory Proposal, Ergon Energy plans our subtransmission network to remain within these requirements throughout the relevant regulatory control period.

Options for augmentation projects have been evaluated using NPV to determine the impact of all costs and benefits and their relevant timing to ensure overall least cost solutions will be implemented to resolve identified constraints and that the level of risk in the network is maintained at acceptable levels.

Distribution program

A 15 per cent reduction to the distribution augmentation forecast is not justified on the available evidence. As such, we have not amended our October Regulatory Proposal to reflect the AER's Preliminary Determination. However, we have refined our expenditure forecasts to reflect reductions in the number and scope of (distribution) specified projects that have resulted from updating the distribution network demand forecasts and reviewing risk assessments for all studied options during the development of this proposal.

Specified projects – Distribution

We have reduced our specified projects program as a result of a revised demand forecast (based on 2013-14) and associated network constraints. Our supporting submission, *CIA Response*, provides additional evidence which supports this. Ergon Energy considers our proposed reduction is appropriate and provides a prudent exposure to risk.

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[54] AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 6 – Capital expenditure*, April 2015, p54.

Unspecified projects – Distribution

Ergon Energy believes that our October Regulatory Proposal for unspecified distribution augmentation was appropriate. This is one of the key investment sub-categories supporting frequent un-modelled problems on distribution high voltage and low voltage networks. Our supporting submission, *CIA Response,* provides additional evidence which supports this.

Impact of solar system installations – Distribution

Ergon Energy maintains that our October Regulatory Proposal included an appropriate level of expenditure for this sub-category. The AER's reduction in the forecast expenditure for photovoltaic augmentation was not warranted on the evidence provided.

A large amount of relevant evidence as well as a business case demonstrating an economic basis for the need to invest was supplied in the original submission. In addition, our supporting *CIA Response* document notes since the original submission was made, the Queensland Government has announced a policy of having photovoltaic (PV) generation systems on one million roofs throughout the state. This policy makes the business case to perform works to address resulting voltage issues on the network even more compelling. Ergon Energy has also provided additional evidence about the negative impact of PV systems on distribution networks.

Estimating Process – Distribution

The conclusions from the AER's consultant, EMCa, indicating systemic over-estimation of project costs are unfounded. Ergon Energy has developed estimating codes specifically for the distribution augmentation projects that utilise building blocks based on actual costing elements from recently completed projects. In addition, for some specific cases, it is not clear if distribution lines may be overhead or underground until community consultations are completed once the project has commenced and this has to be considered at the planning report stage. The overall expenditure is based on realistic estimates of the general outcomes of these negotiations.

Risk assessment

Some statements by EMCa regarding our risk assessment process are incorrect. Our supporting submission, *CIA Response,* provides further evidence explaining our risk assessment techniques and why our risk assessment processes are sound.

Distribution load forecasting

Some statements by EMCa regarding how our load forecasting is applied to distribution networks are incorrect. Our supporting submission, *CIA Response,* provides additional explanation about the proportion of distribution augmentation programs driven by load growth and the impact of demand forecasting on projects. Specifically, the distribution load forecasting process is closely linked to Ergon Energy's demand forecast.

Power quality and reliability

Ergon Energy acknowledges the AER's preliminary position to accept the proposed expenditure forecasts for quality of supply and network reliability expenditure.

Other system-enabling capital expenditure

Ergon Energy appreciates the AER's endorsement of the need for expenditure in the other system-enabling area. However, we do not agree there is a systematic bias of 15 per cent associated with estimating and business and risk justification. Ergon Energy has provided as part of our submission detailed documents describing our estimating methodology. Particularly in the area of Operational Technology, estimating is on a per project basis that has costs come from vendor quotes, rigorous cost per point information and very detailed costing allocation. Ergon Energy has also provided detailed documentation associated with the safety and environmental implications for programs in the areas of AC systems, LV spreaders and fuses, and transformer bunding.

Unexplained capital expenditure

As noted in Section 3.1.3, the AER misinterpreted the information in our October Regulatory Proposal and incorrectly formed the view that a residual amount of expenditure of $33 million that was “unexplained”. The “unexplained” capital expenditure is due to different escalation methodologies applied to re-state forecast expenditure in $2014-15 in:

- the Reset RIN
- the Forecast Expenditure Summary documentation.

The Reset RIN forecasts include full labour, materials and CPI cost escalation, while the expenditure stated in the Forecast Expenditure Summary documentation only includes escalation for CPI.

While the justification of the non-CPI (material and labour) real cost escalation will be discussed in other parts of Ergon Energy’s submission, the removal of $33.1 million from the augmentation expenditure forecast (in isolation) effectively results in this amount being deducted twice from Ergon Energy’s total submission. Further detail is provided in the *Reset RIN Material Issues* document.

9.5. Customer connections expenditure

9.5.1. Preliminary Determination

The AER accepted our forecast connections capital expenditure of $279.5 million. The AER was of the view that our forecast was consistent with forecast drivers in construction activity in Queensland. It also accepted our proposed capital contributions forecast of $158.3 million.

9.5.2. Stakeholder feedback and other influencing factors

Several stakeholders supported comments from the CCP that there was an unsubstantiated increase in customer connections expenditure between periods and called on the AER to ensure there were appropriate justifications for this increase.[55]

Our response to the AER’s Preliminary Determination and stakeholder feedback has been driven by a couple of additional factors:

- We have a better understanding of what we are likely to spend in 2014-15 for this category of expenditure and how it affects our estimates.
- We have updated demand forecasts for the period.

[55] Far North Queensland Regional Organisation of Councils, Op. cit, p3; Alliance of Electricity Consumers, Op. cit, p16; Origin Energy (2015), *RE: Submission to Queensland Electricity Distributors’ Regulatory Proposals*, 30 January 2015, p8; Energy Users Association of Australia (2015), *Submission to Ergon Energy (Ergon) Revenue Proposal (2015/16 to 2019/20)*, 30 January 2015, p22; and Queensland Resources Council (2015), *Ergon Energy Determination 2015-2020*, 30 January 2015, pp10-12.

9.5.3. Our response

Ergon Energy notes the AER's Preliminary Determination on customer connections expenditure and capital contributions is consistent with our October Regulatory Proposal.

Customer initiated investment in 2014-15 has been lower than expected due to a reduction in customer applications and customers proceeding with connection enquiries. This reduction has impacted expenditure in Large Customer Connections Constructed, Commercial and Industrial Customer Requested Works and works on Subdivisions. These declines are consistent with declines in Queensland non-residential investment indicators that have significantly weakened following the completion of Curtis Island LNG construction projects.

This reduction is not inconsistent with the AER's assessment against the trends in forecast construction activity in Queensland as per "Figure B.2 Connection capex and non-residential construction activity" of the Preliminary Determination.[56]

We investigated comments from the CCP regarding the uplift in customer connections expenditure from historic trend. Through this investigation, we identified errors in the historic RIN template provided to the AER. We have updated these historic numbers accordingly.

Revisions and updates are reflected in the following documents:

- Appendix B of the Regulatory Proposal
- *07.00.03 – (Revised) Customer Connection Initiated Capital Works Expenditure Forecast Summary*
- *Reset RIN Material Issues*.

9.6. Replacement expenditure

9.6.1. Preliminary Determination

The AER did not accept our proposed forecast replacement expenditure of $894 million. Rather, the AER reduced our forecast replacement expenditure by 24 per cent, arriving at an alternative estimate of $675 million (excluding overheads).

Trend analysis

The AER examined our trend in replacement expenditure over 2001-02 to 2019-20. The AER found:

- our forecast replacement expenditure is above our long term average
- our forecast replacement expenditure is 8 per cent above expenditure in the regulatory control period 2010-15
- there is significant variability in replacement expenditure over time.

Based on these findings, the AER concluded that a more detailed review using other assessment techniques was required.

Predictive modelling

The AER used its replacement expenditure model (the 'repex model') to model replacement in six asset groups: poles, overhead conductors, underground cables, service lines, transformers and

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[56] AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 6 – Capital expenditure*, April 2015, p65.

switchgear. The AER developed a number of different repex models, each using different replacement age and unit costs inputs. This included:

- the base case model, which used replacement life information inputs detailed in Ergon Energy's RIN (both historical and forecast)
- the calibrated model, which applied replacement lives and standard deviations based on Ergon Energy's replacement volumes from the last five years. This scenario benchmarks Ergon Energy to our observed historical replacement practices
- the benchmarked model, which used unit costs and replacement lives from the category analysis benchmarks.

Based on its predictive modelling, the AER indicated that an efficient level of replacement expenditure would be $449 million. This includes our forecast replacement expenditure for the poles and overhead conductors, and the total calibrated model replacement expenditure amount for the four remaining categories

Technical review

In addition to the above, the AER engaged EMCa to review our proposed replacement expenditure. EMCa generally considered our forecast was upwardly biased and there was insufficient justification or top-down challenge of certain elements. In particular, EMCa found:

- There was insufficient analysis supporting the timing and volume of activity. For example, there was bias towards bulk replacements of specific asset categories, without justification for the timing.
- Our risk framework may have led to an overestimation bias through the inclusion of low risk projects without adequate justification.
- A price cap objective does not necessarily lead to prudent and efficient capital expenditure.

The AER considers EMCa's findings support the outcomes of its other assessments. That is, our proposed replacement expenditure should be substituted with a lower value.

Unmodelled replacement expenditure

Pole top structures, Supervisory Control and Data Acquisition (SCADA)[57] and "Other" replacement expenditure were not modelled in the repex model. Instead, the AER relied on trend analysis and EMCa's findings. The AER was only satisfied with our forecasts for the "Other" category. The AER's assessment is discussed below.

SCADA, network control and protection

The AER noted there was a step increase in our forecast replacement expenditure on SCADA in the first two years of the regulatory control period 2015-20, followed by expenditure in the remaining years which was slightly higher than the average SCADA replacement expenditure incurred in the previous period. Further, EMCa considered there was insufficient justification for the change in performance and risk levels for the proposed replacement expenditure.

Based on these findings, the AER substituted our forecast of $163 million with our historical replacement expenditure (2010-15) of $126 million.

[57] Includes network control and protection.

Pole top structures

Ergon Energy's forecast replacement expenditure on pole top structures was 69 per cent more than the regulatory control period 2010-15. This was primarily driven by our proposed sub-transmission line pole top replacement program. While EMCa agreed with the development of a targeted program to manage these pole tops, it did not believe there was sufficient analysis to support the timing, volume and cost. Consequently, the AER substituted our proposed pole top replacement expenditure with our historical replacement expenditure.

Other replacement expenditure

The AER accepted our forecast replacement expenditure of $38 million, since it was consistent with historical replacement expenditure and EMCa did not identify any systemic issues.

Network health indicators

The AER reviewed two high level indicators of network health to inform the need for replacement expenditure. The AER found:

- the stable trend in residual asset lives does not suggest there are asset health issues that require increases in proposed replacement expenditure
- utilisation on the network should not have had a material impact on asset deterioration.

9.6.2. Stakeholder feedback and other influencing factors

Many stakeholders and the CCP were sceptical of expenditure focused toward ageing infrastructure.[58] The CCP suggested the asset age is not increasing and therefore increased expenditure is not justified. Stakeholders sought drastic reductions in forecasts back to pre-2010 levels.[59] Origin Energy suggested our SCADA expenditure requires specific examination[60] and the Energy Users Association of Australia stated that other system expenditure could be further reduced.[61]

Our response to the AER's Preliminary Determination and stakeholder feedback has been driven by a couple of additional factors:

- We have a better understanding of what we are likely to spend in 2014-15 for this category of expenditure and how it affects our estimates.
- ROAMES technology has identified low voltage clearance issues that need to be rectified.

9.6.3. Our response

Our revised Regulatory Proposal includes changes to our forecasts, reflecting:

- updates to our expected 2014-15 expenditure for this category
- an additional program of works to address the low voltage conductor clearance issues, leading to an increase in our Asset Renewal forecasts. Unlike in NSW, Ergon Energy is required to ensure all of our assets comply with conductor clearances set out in regulation. This includes conductor clearances to vertical and horizontal structures, vertical clearances

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[58] Chamber of Commerce and Industry Queensland, Op. cit, p11; Cotton Australia, Op. cit, p7; Canegrowers, Op. cit, p4; QCOSS, Op. cit, pp55-56; and Total Environment Centre, Op. cit, p15.
[59] Alliance of Electricity Consumers, Op. cit, p13; and Chamber of Commerce and Industry Queensland, Op. cit, p13.
[60] Origin Energy, Op. cit, p1.
[61] Energy Users Association of Australia, Op. cit, p22.

over roadways, places navigable by vehicle and paths, clearance between voltage levels, and exclusion zones for trained, authorised and untrained persons. We also must mitigate, as far as is reasonably practical, significant public safety issues.[62]

These changes have been reflected in the following documents:

- Appendix B of our Regulatory Proposal
- *07.00.01 – (Revised) Asset Renewal Expenditure Forecast Summary*
- *07.00.09 – (Revised) Unit Cost Methodologies for Ergon Energy Summary*
- *07.09.02 – (Revised) Overhead Feeder Circuits Management Plan*.

Ergon Energy notes that while the revised rate of return may impact Condition Based Replacement Modelling outcomes for forecast asset replacement volumes, we have not amended our revised proposal for the consequential renewal increases that may result as a result of the model outcomes.

We have not made any revisions to our October Regulatory Proposal to reflect the AER's Preliminary Determination. Many of the conclusions drawn by the AER are incorrect. In particular, we are concerned by:

- the selective use of repex models and model parameters
- the validity of the repex model assumptions
- the use of ALARP versus SFAIRP risk approach
- comments made by the AER and its consultant regarding top down restraint
- the AER's approach to unmodelled repex which resulted in the removal of mandatory programs (e.g. earthing defect thresholds and splice replacement) and safety mitigation programs (e.g. laminated crossarm removal and subtransmission pole topping).

A summary of our concerns in relation to the AER's Preliminary Determination is below.

Our detailed submission on replacement expenditure is contained in *Asset Renewal Response*. This document details our response on the issues raised by the AER, its consultant and stakeholders, including the reasons why we have not updated our proposal to reflect the Preliminary Determination. It also sets out the changes Ergon Energy has made in our revised Regulatory Proposal.

Errors in forecasts

In light of the AER's Preliminary Determination, we have identified an error in the RIN tables which affects the Asset Renewal forecast. Three business cases (with a total value of $40 million in 2015-20) were inadvertently netted off capital expenditure for Standard Control Services on the basis they related to Default Metering Services. Our submission document, *Reset RIN Material Issues*, provides further detail.

Trend analysis and predictive modelling

Our *Asset Renewal Response* highlights several problems with the AER's analysis supporting its conclusions surrounding:

- the selective use of repex models
- the validity of the repex model assumptions
- the selective use of repex model parameters

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[62] Refer to *07.01.47 – Conductor clearance BC*.

The AER should not have relied on EMCa's conclusions.

Technical review

We also address some issues inherent in the conclusions drawn by the AER's consultant EMCa. These include:

- use of ALARP versus SFAIRP risk approach
- concerns over the review of the unmodelled expenditure forecast.

From the material before us, EMCa did not review the Other Systems capital expenditure category. It is not clear, therefore, on what basis the claims of systematic biases in subtransmission and distribution forecasts (which in themselves are incorrect) relate to the way the costing model is applied to Other System Enabling capital expenditure. In our view they do not.

9.7. Capitalised overheads

9.7.1. Preliminary Determination

The AER rejected our forecast capitalised overheads. It substituted our forecast of $1,017 million with its own value of $961.8 million. The AER stated that our capitalised overheads should be lower, given the reduction it has made to our total capital expenditure. It considers a $1.0 million reduction in our total capital expenditure should result in a $0.05 million reduction in our capitalised overheads.

SPARQ ICT expenditure

The AER has included our proposed ICT overheads in its alternative capital expenditure estimate, adjusted for lower direct costs. However, the AER raised a number of concerns which it expects Ergon Energy to address in our revised Regulatory Proposal. These include:

- efficiencies identified by the Independent Review Panel on Network Costs and ITNewcom (SPARQ's consultant) do not appear to be captured in the forecasts. That is, the AER expects a cost decrease on the 2012-13 base year level of expenditure
- an over-recovery of financing costs, due to the higher WACC proposed by Ergon Energy compared to the AER's Preliminary Determination. Further, there is also a potential for over- and under-recovery in the future as the WACC will no longer be constant over the regulatory control period
- the majority of SPARQ ICT costs have not been market tested and there is scope for additional efficiencies through reform
- ICT costs are not being transparently reported. The AER considers they should be captured as "Non-Network – IT & Communications Expenditure", rather than as overheads. It also noted that an off balance sheet treatment makes it difficult to assess the trend in ICT capital expenditure. There would be greater transparency if the ICT assets were included in the RAB.

9.7.2. Our response

We have not changed our proposal to reflect the AER's Preliminary Determination. We have provided a response to the issues raised by the AER (*Capitalised overheads and ICT expenditure – Response*), which includes an independent report from KPMG on SPARQ.

Ergon Energy also notes the AER's analysis of our substitute capital expenditure forecast to derive a benchmark mean ICT capital expenditure value of 4.48 per cent.[63] In fact, the KPMG 2013 corporate benchmark for regulated ICT capital expenditure as a percentage of total regulated capital expenditure was 7 per cent. Additionally, given the cyclic nature of ICT investments, we consider that assessment of this metric itself is inappropriate and that a more holistic approach to assessing the prudent and efficient level of ICT capital expenditure is required. By way of example, the cost of replacing Ergon Energy's enterprise resource planning system software is not a function of our augmentation expenditure levels or other system capital expenditure levels.

Finally, we have amended the asset service fee to reflect lower financing costs implicit in the annual SPARQ charge. This is incorporated in our overhead forecast. Ergon Energy must allocate this forecast to both capital and operating expenditure based on what the AER has previously approved. Our forecasts reflect the AER-approved cost allocation arrangements.

9.8. Non-network capital expenditure

9.8.1. Preliminary Determination

The AER did not accept our proposed non-network capital expenditure of $506.3 million (excluding overheads). Rather, the AER determined an alternative allowance of $420.3 million (excluding overheads).

The AER assessed our long term non-network capital expenditure trends. Its analysis shows that our forecast non-network capital expenditure is at historically low levels, with the exception of the 2015-16 and 2016-17 years. The spike in expenditure was driven by buildings and property capital expenditure and fleet capital expenditure. Consequently, the AER reviewed these categories to confirm the need for and timing of the proposed expenditure.

The AER accepted our IT and plant and equipment categories as they were forecast to remain at historically low levels.

Buildings and property capital expenditure

Major property projects

The AER has included the costs associated with the major property projects at Rockhampton, Maryborough and Toowoomba in its forecast. However, it excluded the Townsville major project. The AER stated:

- While there was generally sufficient justification to support the need, costs and timing of the proposed projects, Ergon Energy had excluded the 'do nothing' option of ongoing maintenance from our options ranking process for the Townsville major project. The AER noted the 'do nothing' option is actually the highest NPV option. It therefore considers the options evaluation process undertaken by Ergon Energy does not necessarily support our preferred option. Consequently, it did not consider that a prudent operator would necessarily proceed with our preferred option.
- Our options analysis should be updated to consider the current (Stage one) redevelopment and 'do nothing' options assuming the successful completion of Stage one.

[63] AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 6 – Capital expenditure*, April 2015, p93.

- The AER considers that Stage two is not required to be completed as a necessary follow-on to the completion of Stage one.

Minor property program

The AER accepted our forecast capital expenditure for minor property projects.

Property disposals

Ergon Energy did not forecast property disposals in our modelling as the disposals were dependent on approval of the proposal capital program. Based on the AER's decision to include an allowance for the Rockhampton, Maryborough and Toowoomba major property projects, the AER has included disposals related to these projects of $13.2 million.

Fleet capital expenditure

The AER rejected our forecast fleet capital expenditure. Rather, it substituted its own amount of $160 million. The AER noted that a number of fleet asset categories are forecast to increase in both quantity and unit costs.

It considered:

- Our optimal replacement ages are less than those of other DNSPs in the NEM (e.g. four years for 2WD passenger vehicles and 4WD vehicles compared to a five and six year replacement criteria used by other DNSPs).
- The forecast increase in operating expenditure associated with passenger vehicles is not justified.
- Our estimated costs for Elevated Work Platforms for heavy vehicles uses the highest estimated unit cost for all fleet assets of this type.
- Our claim that customers believe a local presence is important is not supported by evidence, or that an increase is required to maintain this presence.
- Our forecast fleet capital expenditure should be lower than the regulatory control period 2010-15, to reflect lower staffing levels.
- There is a lack of management oversight of financial and operation outcomes for our fleet assets that are not the responsibility of the Fleet Manager.
- Vehicle standards sometimes result in higher than required fleet capital expenditure.

9.8.2. Stakeholder feedback and other influencing factors

The Energy Users Association of Australia noted our non-network expenditure is forecast to reduce. Notwithstanding this, they requested the AER to review our forecasts in light of its decisions on capital and operating expenditure.[64]

At the end of last year, we began a process for reviewing our approach to fleet management and forecasting. We have incorporated learnings from other determination processes in developing a revised forecast.

9.8.3. Our response

Our revised Regulatory Proposal includes changes to our forecasts, reflecting:

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[64] Energy Users Association of Australia, Op. cit, p22.

- updates to our expected 2014-15 expenditure for this category
- a revised fleet expenditure forecast, taking into account the AER's Preliminary Determination and revisions to our fleet management and forecasting approaches.

Our non-network capital expenditure forecast has also been revised to include new values for property disposals, consistent with the AER's Preliminary Determination.

We have also provided additional evidence in support of our revised Regulatory Proposal.

We have not revised our proposal for all elements of the AER's Preliminary Determination, particularly for property. We have some concerns with the AER's decision. These concerns are summarised below, and discussed in more detail in our submission *Capex (Non-system Property) Response*. The following section also discusses briefly our response to the AER's Preliminary Determination with respect to fleet capital expenditure.

Buildings and property capital expenditure

Major property projects

Ergon Energy supports the AER's preliminary decision to approve our Rockhampton, Maryborough and Toowoomba major projects. However, we do not agree with the AER's position in relation to the Townsville (Garbutt) major project.

This is because:

- In assessing the business case, the AER evaluated the financial efficiency of the preferred option ('A') against the 'do nothing' option ('E') which does not address any of the fundamental risks and issues on the Garbutt site.
- The AER did not appear to review or consider the efficiency and prudency of any non-financial factors between the preferred option and the 'do nothing' option.
- The AER did not appear to consider any of the dependencies between stage one and stage two of the overall Garbutt Redevelopment project, including various planning compliance requirements.
- The AER justified its position on stage two by referring to the Evans & Peck report, which considered stage one as 'stand-alone'.
- The AER also appears to justify its position by using circular reasoning (i.e. that as funding approval is required by the AER, the AER is satisfied that approval is not required).

Our position is supported by the following amended and additional documents:

- *Capex (Non-system Property) Response*
- *Garbutt Townsville Assumptions Calculations – 30 years*
- *Property – Letter to Chair – Investment Approval – Garbutt*
- *Property – Development Application Decision Notice Garbutt*.

Fleet capital expenditure

Ergon Energy notes that the AER's reference to Ergon Energy's proposed fleet capital expenditure is incorrect. We proposed $203 million. Further this amount represents fleet expenditure for all Direct

Control Services, not just Standard Control Services expenditure. We advised the AER of this on 6 February 2015 in response to the AER's request.[65]

Our revised Regulatory Proposal and forecasts reflect a new approach by Ergon Energy in respect to fleet management and forecasting, taking into account our own review of other NSP approaches, and the AER's decisions for other NSPs. The AER's Preliminary Determination in April 2015 confirmed Ergon Energy's proposed change of direction in this space.

As a result, our revised proposal responds favourably to the concerns raised by the AER in its Preliminary Determination:

- We have benchmarked our methodology and approach with those of other NSPs and have listened to what the AER said in its determination for NSW, as well as our own Preliminary Determination.
- We have moved to a kilometre-based not an aged-based profile for determining future investment needs for a selection of our fleet. A kilometre-based approach is consistent with NSP industry standards, while having regard to our obligations.
- Our forecasting methodology is developed at a more granular level, which allows us to also apply prices at a more granular level, responding to the AER's concerns regarding unit prices for Elevated Work Platforms.

The AER's reference to operating expenditure for passenger vehicles appears to reference a supporting document from UMS for the purpose of determining the optimal replacement point. We note that these forecasts were the basis of what we asked for and were only used for modelling purposes. Since we have now amended our forecasting approach, the AER's concerns now appear redundant.

In our revised Regulatory Proposal, we have included a summary of fleet assets to headcount, which, over the course of the regulatory control period 2010-15, indicates an improvement of 6 per cent for the employee to fleet asset ratio.

Finally, vehicles are included in our catalogue taking into account the following criteria:

- safety
- operational suitability
- technical compliance
- manufacturers' support
- operational expenditure.

The luxury name plate vehicles referenced by the AER in its Preliminary Determination (e.g. Mercedes) at face value may appear to be an unwarranted expense. However, they have been selected after considering the aforementioned factors. They meet safety, compliance and suitability requirements at a lower operating cost than similar types of vehicles.

9.9. Demand management

9.9.1. Preliminary Determination

The AER has not included an explicit reference in our capital or operating expenditure forecasts for demand management. It is of the view that the efficient use of demand management can be

[65] Ergon Energy (2015), *Response to AER Information Request: AER EE 016*, 6 February 2015.

promoted through the incentive framework, the Regulatory Investment Test for Distribution and the Distribution Annual Planning Report.

9.9.2. Stakeholder feedback and other influencing factors

Many stakeholders suggest that networks should emphasise demand management activities more[66] and have asked the AER to be more diligent in looking for demand management opportunities when assessing forecasts. Some stakeholders sought more targeted arrangements for either underutilised assets[67] or low income and vulnerable high energy use households.[68] QCOSS supported the continued investment in demand management by the distributors in principle and supports both distributors' broad and targeted approaches.[69] Similarly, the Total Environment Centre and Queensland Farmers' Federation supported our targeted approach.[70]

The Queensland Resources Council encouraged the AER to challenge our proposed investment in demand management, given demand management is an initiative driven by customers (e.g. through their response to network tariffs).[71]

9.9.3. Our response

Ergon Energy prides itself on seeking to advance non-network alternatives as the primary solution to constraints, rather than as an alternative to a traditional supply side solution. We have made minor changes to our proposal, but continue to advocate for sufficient funding to continue initiatives for managing demand on the network. Our detailed response is contained in *Demand Management – Response.*

9.10. Demand forecasts

9.10.1. Preliminary Determination

The AER was satisfied with our system demand forecast, since it reasonably reflects a realistic expectation of demand. The AER was satisfied that our augmentation expenditure forecast is based on a realistic expectation of demand. However, it expects Ergon Energy's revised Regulatory Proposal to take into account the AEMO's connection point demand forecasts for Queensland. The AER also expects our revised Regulatory Proposal to take into account more up-to-date data and provide further information on the reconciliation of these forecasts with our zone-substation forecasts.

9.10.2. Stakeholder feedback and other influencing factors

Most stakeholders disputed the demand forecasts put forward by Ergon Energy.[72] Origin Energy considers the system demand forecasts reflect a reasonable expectation of future demand, but expects the AER to consider AEMO's demand forecast in its Substitute Determination.[73] QCOSS was disappointed much of the information was not available.[74] Nevertheless, QCOSS does not

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[66] Queensland Consumers Association (2015), *Submission to AER on Queensland Electricity Distribution Regulatory Proposals 2015-16 to 2019-20,* 17 January 2015, p3; and QCOSS, Op. cit, pp83-84.
[67] Queensland Consumers Association, Op. cit, p3; and Far North Queensland Regional Organisation of Councils, Op. cit, p3.
[68] QCOSS, Op. cit, p83.
[69] QCOSS, Op. cit, p84.
[70] Queensland Farmers' Federation, Op. cit, p8; and Total Environment Centre, Op. cit, p8.
[71] Queensland Resources Council, Op. cit, p16.
[72] Alliance of Electricity Consumers, Op. cit, pp10-12; Canegrowers, Op. cit, p3; and QCOSS, Op. cit, p45.
[73] Origin Energy, Op. cit, p6.
[74] QCOSS, Op. cit, p43.

expect economic activity to be a key driver for increased peak demand in the regulatory control period 2015-20.[75]

9.10.3. Our response

Ergon Energy has reviewed the material put forward by the AER's consultant, EMCa. We do not agree with EMCa's comments in relation to demand forecasting. Consequently, we disagree with the conclusions drawn by the AER. Our detailed submission highlights reasons for our concerns on EMCa's report and why the AER should not rely on areas of the report where we do not agree with their comments or conclusions.

In relation to the AER's comment that the Substitute Determination will take into account AEMO's connection point forecast for Queensland, Ergon Energy notes that this will be the first time that AEMO has prepared such a forecast for Queensland. Therefore, there is no history on which to determine if the process AEMO will be using is robust and will provide a sufficient level of accuracy. In addition, due to the timing of its release, there will be no opportunity for Ergon Energy to examine the final forecast prior to the submission of our revised Regulatory Proposal. This makes it impossible for Ergon Energy to account for, examine or explain any differences between AEMO's connection point forecast and our demand forecast. Ergon Energy has received a preliminary version of AEMO's 2015 connection point forecast, which we note shows a higher growth rate than that forecast by Ergon Energy for the regulatory control period 2015-20 using both our May 2014 and May 2015 forecasts.[76]

Our revised Regulatory Proposal corrects some minor factual errors about our demand forecasting methodology.

9.11. Real material cost escalation

9.11.1. Preliminary Determination

The AER did not accept the real material cost escalators proposed by Ergon Energy. Instead, it applied a zero per cent real cost escalation. The AER considered:

- there is a degree of potential inaccuracy in commodity forecasts and a zero per cent real cost escalation is likely to provide a more reliable estimation
- it is difficult to assess the accuracy and reliability of our forecasts as a predictor of the prices of assets without supporting evidence of our model's past performance
- we did not provide any supporting evidence to demonstrate that we considered the impact of material exogenous factors on the cost of physical inputs not captured by the material input cost models used by Ergon Energy.

The AER considered our labour and construction cost escalations more reasonably reflect a realistic expectation of the cost inputs required to achieve the capital and operating expenditure objectives.

Materials input costs

The AER decided that our forecasts were not reliable, because we did not provide:

- any supporting evidence demonstrating how our materials escalation forecasts reasonably reflect changes in prices we paid for assets in the past

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[75] QCOSS, Op. cit, p45.
[76] Refer to *Interim Submission Addendum – Demand Forecasts* (confidential).

- information explaining the basis for the weightings of commodity inputs for each asset class or that the weightings applied have produced unbiased forecasts.

Materials input cost forecasting

The AER considers that we have not provided an adequate explanation for (or quantification of) the relationship between the commodity inputs used by Jacobs/SKM and the physical assets we have purchased. Further, we have not taken into account material exogenous factors.

Materials input cost mitigation

The AER believes Ergon Energy can mitigate the magnitude of any input cost increases. This could be achieved by commodity input substitution, capital and operating expenditure substitution, operational change and productivity increases.

Forecasting uncertainty

The AER indicated there is likely to be significant uncertainty in forecasting commodity input price movements. The AER highlighted the following:

- It considers risks associated with changes in material input costs can be mitigated by including hedging strategies or price escalation provisions in supplier contracts.
- There is potential for double counting if contract prices reflect the allocation of risk from the service provider and Ergon Energy.
- A cost based approach reduces incentives to manage capital expenditure efficiently and may result in over-forecasting.
- Our material input escalation may not be representative of the full set of inputs or input choices. Further, there is a risk of bias, if the selected inputs are forecast to increase in price over the period.
- The commodities boom has subsided, suggesting the need for a material cost escalation has also reduced.

9.11.2. Stakeholder feedback and other influencing factors

We have received updated materials and labour escalation forecasts from Jacobs and have incorporated the revised escalation rates and forecasts in our expenditure forecasts and associated documentation.

As noted in Section 3.1.1, the AER has also indicated it will correct two errors relating to materials and labour cost escalators, and the removal of all CPI and non-CPI escalation between 2012-13 and 2019-20 in its Substitute Determination.

9.11.3. Our response

Our revised proposal incorporates revised expert independent advice and analysis of escalation rates for materials and labour, taking into account updated market information. An updated spreadsheet, *06.02.07 – Jacobs: Addendum Cost Escalation Factors 2015-20,* is attached to our revised Regulatory Proposal.

In respect of labour cost escalation, we have incorporated these changes in our operating expenditure forecast.

Our proposal has not been revised to reflect the AER's preferred approach to materials escalation. The AER is incorrect in assuming CPI is as good as any other measure to determine the likely movement in prices underpinning capital expenditure items. While the impact of adopting the AER's approach is minimal in the regulatory control period 2015-20 (in fact for some asset classes it makes the forecast higher), the AER's decision sets a concerning precedent for periods where the underlying indices for materials may be significantly different (higher or lower) than CPI. Our supporting submission *Capex (Real labour and materials escalations) – Response* provides additional evidence and justification for the inclusion of a materials escalator in forward forecasts.

In respect to the error acknowledged by the AER, we have included the attached document, *Error in escalation adjustments for SCS capital expenditure,* to restate the information we have already provided to the AER. We have also included an independent assessment of the AER's error and attached their conclusions. This independent report is entitled *KPMG – Review of the Capex Escalation Adjustment.* This independent report confirms the conclusions reached by Ergon Energy and the AER in respect of the error.

9.12. Contingent projects

9.12.1. Preliminary Determination

Ergon Energy nominated one contingent project in our October Regulatory Proposal – the Cairns Northern Beach Supply Reinforcement project. We also put forward, for consideration, a general contingent project to cover large customer connections that are unknown to Ergon Energy at this time, but which will result in a material amount of shared network augmentation during the regulatory control period.

The AER rejected the Cairns Northern Beach Supply Reinforcement project and our general contingent project for large customer connections. The AER indicated:

- Cairns Northern Beach Supply Reinforcement project – Ergon Energy had relied on an inflated demand forecast and had not fully explored deferment options. It also did not consider the trigger event met the NER requirements and the project did not meet the contingent project threshold
- General – this project did not meet the definition of a contingent project, since there was no specific project.

9.12.2. Other influencing factors

Ergon Energy has reassessed our Network Capital Plan for projects whose forecast capital expenditure exceeds the contingent project threshold. Of these, we considered whether the project:

- has an appropriate defined trigger event
- is reasonably required to meet the capital expenditure objectives
- reasonably reflects the capital expenditure criteria.

We did not identify any new contingent projects through this assessment process.

While there is still some uncertainty around the development timeframes for the Cairns Northern Beach Supply Reinforcement project, it is now likely that any network reinforcement capital expenditure related to this development will not be required until the subsequent regulatory control period.

9.12.3. Our response

Ergon Energy has reviewed the Cairns Northern Beach Supply Reinforcement project against the contingent project criteria. Given the likelihood that any network reinforcement capital expenditure will not be required until the regulatory control period 2020-25, we have decided to withdraw this project.

We also note the AER's decision to reject our general contingent project for unknown large customer connections.

Since we have not identified any additional contingent projects and we agree with the AER's Preliminary Determination, we have removed our supporting document, *07.09.16 – Proposed Contingent Projects*, from our revised Regulatory Proposal documentation suite. We have also updated Chapter 4 of our Regulatory Proposal to reflect our revised position.

10. Operating expenditure

This section summarises our response to the AER's decision on our operating expenditure allowance.

10.1. Preliminary Determination

The AER did not accept our proposed total operating expenditure allowance of $1,821.1 million for the regulatory control period 2015-20. Instead, the AER determined a total operating expenditure allowance of $1,629.9 million.

Table 8: AER's preliminary determination on Ergon Energy's forecast operating expenditure, 2015-20

$m (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Ergon Energy's proposal	349.6	356.1	363.6	372.9	379.0	**1,821.1**
AER Preliminary Determination	314.4	320.3	325.4	332.0	337.8	**1,629.9**
Difference	(35.2)	(35.8)	(38.3)	(40.9)	(41.1)	**(191.3)**

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 7 – Operating expenditure*, April 2015, p9.

Since the AER's alternative estimate was lower than our total forecast operating expenditure, it concluded that our proposal did not reasonably reflect the operating expenditure criteria set out in clause 6.5.6(c) of the NER.

Further information on the AER's assessment process and positions is provided below.

10.1.1. Base operating expenditure

The AER used a number of techniques to assess our base year operating expenditure. Our supporting submission *Opex (Base Year) – Response* summarises the AER's findings on the main techniques.

Based on its analysis, the AER decided our actual base operating expenditure is materially inefficient. As such, it adjusted our base year operating expenditure. The AER used its preferred benchmarking model (Cobb Douglas stochastic frontier analysis) as the starting point. Then, it applied two adjustments:

- The AER made a 24.4 per cent adjustment to account for differences in operating environment factors not accounted for in the benchmarking model.
- It used a benchmark comparison point of 0.77 in the benchmarking model. This is the efficiency score for the business at the bottom of the upper third of companies in the benchmark sample (i.e. AusNet Services).

Applying the above approach resulted in a reduction to our expenditure using our revealed operating expenditure of $36.5 million or 10.7 per cent.

10.1.2. Adjustments to base year expenditure

In response to our October Regulatory Proposal the AER:

- did not consider it necessary to adjust individual operating expenditure categories to remove or add back non-recurrent changes in operating expenditure in the base year
- did not explicitly remove our proposed movements in provisions from our base year operating expenditure because it departed from our revealed costs and substituted its own base year
- removed expenditure relating to services that will not be classified as Standard Control Services in developing its alternative operating expenditure estimate.

10.1.3. Rate of change

The AER has applied the forecast rate of change from its substituted base year (2012-13). In developing its forecast, the AER adopted a 62 per cent weighting for labour and 38 per cent for non-labour. Its forecast for the labour price growth was based on the forecast Wage Price Index for the Electricity, Gas, Water and Waste Services industry and its forecast for non-labour growth is CPI.

Ergon Energy calculated two growth drivers in our October Regulatory Proposal:

1. Customer growth – the annual forecast growth in customer numbers over the regulatory control period 2015-20
2. Network growth – a simple average of the forecast annual growth in zone substation capacity, distribution line length and the number of distribution transformers over the regulatory control period 2015-20.

The customer growth driver was applied to other operating and maintenance costs and overheads, while the network growth driver was applied to network operating costs and network maintenance costs.

The AER rejected Ergon Energy's inputs for rate of change but found there was no material difference between our output growth factors, once economies of scale are excluded. The AER considers economies of scale form part of the productivity growth factor.

Productivity

Ergon Energy applied a productivity growth factor of 1 per cent per annum to all direct and support costs, which was rejected by the AER. The AER considered our forecast productivity reflected our 'catch up' to the efficient frontier and is no longer relevant given the changes the AER has made to our base operating expenditure. Therefore, the AER applied zero per cent forecast productivity.

10.1.4. Step changes

Our October Regulatory Proposal included step changes for non-network ICT, AEMO testing requirements and non-network alternatives. In its Preliminary Determination, the AER also considered the following costs, proposed by Ergon Energy as one-off or bottom up adjustments, to be step changes:

- parametric insurance
- remediation of contaminated land
- regulatory reset costs
- overheads reallocated to operating expenditure.

The AER rejected these step changes using predetermined criteria.

10.1.5. Debt raising costs

The AER's Preliminary Determination on our debt raising costs is contained in Section 6.5.1.

10.2. Stakeholder feedback

Many submissions expected the AER to significantly reduce operating expenditure forecasts.[77] Some responses asked the AER to look closely at other operating costs,[78] overtime rates,[79] overheads,[80] salaries,[81] ICT,[82] maintenance and vegetation management.[83] Submissions were also very negative to any transition towards a forecast determined by benchmarking.[84]

10.3. Other influencing factors

Our October Regulatory Proposal used the most recently audited financial accounts to establish the base year for future forecasts. Since that time, audited accounts for 2013-14 have become available and we have updated our forecasts to reflect more updated information.

We have identified a new step change in operating expenditure requirements for additional workload associated with anticipation that the Minimalist Transitioning Approach (MTA) will cease to apply. Currently, Ergon Energy is allowed to operate a less onerous information management regime when providing National Metering Identifier information to retailers and AEMO. This regime is known as the MTA.

In November 2014, the AER released its annual benchmarking report. This report was later than the statutory time frame allowed, and the ability for Ergon Energy to properly understand and account for this report in developing our original forecasts was limited. Further, the AER's report raised more questions than answers. We have looked at the outcomes of the report and have considered the extent to which we should incorporate them in developing our forecasts.

The AER's approach to substituting an NSP's expenditure forecast using revealed costs with its own single point estimate has been the subject of considerable debate and conjecture in other distribution determination processes. Ergon Energy has been participating in these processes as the AER has tended to apply a consistent approach and methodology across determinations. Our supporting submission *Opex (Base Year) – Response* provides a list of the information we have considered in our response to the AER's Preliminary Determination.

10.4. Our response

We have revised our Regulatory Proposal in the following ways:

- We have adopted the most recently available audited accounts (2013-14) as the base year, consistent with AER requests and precedent.
- We have made a one-off adjustment to the base year, taking into account a number of factors, including:

[77] Alliance of Electricity Consumers, Op. cit, pp19-22; Canegrowers, Op. cit, p5; Energy Users Association of Australia, Op. cit, p4; and Total Environment Centre, Op. cit, p17.
[78] Queensland Resources Council, Op. cit, p16.
[79] Australians in Retirement – Cairns and Northern Districts Branch, Op. cit, p3.
[80] Origin Energy, Op. cit, p12.
[81] Chamber of Commerce and Industry Queensland, Op. cit, p15.
[82] COTA Queensland, Op. cit, p2.
[83] QCOSS, Op. cit, p68.
[84] Australian PV Institute, Op. cit, p6; Far North Queensland Regional Organisation of Councils, Op. cit, p3; and QCOSS, Op. cit, p69.

- the AER's preference for movement in provisions
  - some expenditure requirements that may not be recurrent (such as costs to satisfy NER requirements and compliance with AER RINs)
  - our proposed stretch target to deliver best possible price outcomes for customers outlined in our October Regulatory Proposal
  - a review of the rate of change factors, having regard to the AER's preliminary decision
  - the AER's benchmarking report and additional evidence from other NSP determinations
  - other factors the AER has taken into account in its Preliminary Determination.
- We have reviewed the step changes proposed against the AER's decision and, where appropriate have provided additional information to satisfy the AER that the step change in expenditure from the base year is necessary.
- As noted above, we have identified a new step change in expenditure which will need to be incorporated in forecasts.

While we believe the AER's approach to substitution is incorrect, we have attempted to restate our forecasts using the base-step-trend modelling approach the AER has applied in its Preliminary Determination.

More detail of our revised approach and outcomes can be found in the following documents:

- Appendix A of the Regulatory Proposal
- *06.01.01 – (Revised) Operating Forecast Expenditure Summary Document*
- *06.01.04 – (Revised) Step Changes for Operating Costs*
- *07.02.11 – (Revised) Demand Management Overview 2015-20*.

We have added additional evidence to support our revised proposal. This includes, but is not limited to, the following evidence and material we have provided to the AER as part of consultation on our own Regulatory Proposal:

- *Frontier Economics – Taking into account heterogeneity when benchmarking*
- *Huegin – A study of the relevance of the NSW Draft Decision outcome on Ergon Energy's benchmarking results*
- *Huegin – Heterogeneity in Electricity Distribution Networks Testing for the presence of latent classes*
- *Synergies – Comments on the use of benchmarking in economic regulation.*

The AER's Preliminary Determination of operating expenditure is not satisfactory. It places no weight on the legitimate starting point – Ergon Energy's base year recurrent operating expenditure. Rather, it relies heavily on a single point estimate from a complicated and unreliable formulaic expression of NSP data across three countries. The AER engaged its consultant Deloitte to justify the gap between Ergon Energy's actual costs and this single point estimate. The AER's consultant identifies some elements that could explain this gap, but there is very little justification or quantification of these elements and why Ergon Energy's operating expenditure would be lower if they did not exist.

Further, the AER incorrectly rejects all step changes in operating expenditure allowances and partially rejects Ergon Energy's rate of change factors.

A summary of our response is provided below. Our detailed response is contained in *Opex (Base Year) – Response* and *Opex (General) – Response*. We have also provided additional evidence and material to support our positions, including an additional report on benchmarking from Huegin that shows Ergon Energy will be operating at or above the efficient frontier determined by the AER in the regulatory control period 2015-20. This analysis is consistent with other material we supplied the AER that suggested we were operating at a higher level of efficiency than implied by the AER's analysis.

10.4.1. Base operating expenditure

Our understanding of the regulatory framework requires the AER to undertake the task of assessing forecast operating expenditure in the following manner:

- The AER should have based its assessment of operating expenditure using our actual expenditure as the logical starting point, including the trend of expenditure over time. It did not do this.
- The AER should have logically referenced this operating expenditure to the level of expenditure the AER previously set, having been satisfied in an earlier decision that the operating expenditure it had set was efficient. It did not do this.
- The AER should also have logically looked at the incentive mechanisms inherent in Ergon Energy's 2010-15 Distribution Determination. It did not do this.
- The AER should have looked at how Ergon Energy had demonstrated how our actual expenditure and forecast expenditure were grounded in efficiency and prudency principles. It did not do this.
- The AER should have referenced the operating expenditure to a wide range of available benchmarks, preferably contextualised in a robust and comprehensive annual benchmarking report having regard to the various reasons why these benchmarks may differ. It did not do this.
- The AER should have looked at other factors that may indicate why Ergon Energy's base year operating expenditure was representative or unrepresentative of a reasonable forecast. It did not do this.

Our supporting submission *Opex (Base Year) – Response* provides detail around why the process undertaken by the AER was misconstrued within the context of its obligations and discretion. We argue:

- The AER placed undue confidence in its subjectively derived single point estimate to reject Ergon Energy's revealed cost as a logical starting point.
- Most, if not all, factors considered by the AER were driven to the outcome of a single point estimate.
- Alternatives to adjust the revealed cost were not considered.
- A realistic application of its subjectively determined single point estimate to the circumstances of the business was not considered.

10.4.2. Adjustments to base year operating expenditure

We have not revised our proposal for the rate of change factors substituted by the AER. Our supporting submission *Opex (General) – Response* details our response. In summary:

- There is not sufficient evidence for the AER to reject the workload driver categories used in our proposal and substitute with different workload driver categories.
- We hold that the real escalation rates applied by our expert, Jacobs, are reasonable and should be applied.

- We do not agree that the NER limit within period productivity adjustments only to industry productivity. Our revised proposal retains a 0.75 per cent annual reduction in overall operating expenditure each year from 2016-17.

10.4.3. Step changes

Since operating expenditure is largely recurrent, it is generally accepted that expenditure required in the next year will largely be a function of expenditure in the incumbent year, allowing for some trend in output, price, or other factor. There are likely to be changes outside of trend between years which will need to be taken into account if an operating expenditure forecast is realistic and reasonable.

Deviations from trend will often occur because of changes in regulatory arrangements or trade-offs between capital expenditure and operating expenditure. However, there is no evidence that these are the only two factors that will cause deviations in operating expenditure beyond a trend within a period.

To this end, Ergon Energy notes that the term "step changes" and the criteria in which they are calculated is a construct of the AER's Expenditure Forecast Assessment Guidelines, not the NER. It is not open, therefore, for the AER to dismiss costs on the basis that they do not meet its definition of a step change. What is required is an appropriate assessment of total operating expenditure requirements over the period.

The AER too simplistically removed all of Ergon Energy's required adjustments to trended operating expenditure forecasts on the basis that they "assessed them as step changes in formulating our alternative opex forecast."[85]

10.4.4. Debt raising costs

Our response on debt raising costs is contained in Section 6.5.2.

[85] AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 7 – Operating expenditure*, April 2015, p300.

11. Corporate income tax

This section summarises our response to the AER's decision on our corporate income tax allowance.

11.1. Preliminary Determination

The AER did not accept our proposed cost of corporate income tax. Instead, the AER applied an allowance of $204.2 million, which is a 67.1 per cent reduction. This reflects adjustments the AER made to:

- the opening tax asset base (TAB) value as at 1 July 2015
- the remaining tax asset lives
- gamma
- other building block components (e.g. operating expenditure and capital expenditure).

11.1.1. Opening tax asset base

While the AER accepted our approach to establishing the opening TAB as at 1 July 2015, it did not accept our proposed value. It substituted an opening TAB of $6,377.8 million, an increase of $52.7 million. This increase reflects adjustments made to the actual capital expenditure values in our Roll Forward Model.

11.1.2. Remaining tax asset lives

The AER did not accept our proposed approach to estimating the remaining tax asset lives at 1 July 2015. The AER has determined the remaining tax asset lives using a weighted average approach. This involves rolling forward the approved remaining tax asset lives at the start of the regulatory control period 2010-15 having regard for the amount of actual capital expenditure in that period. The AER was concerned that our average depreciation approach tends to result in lower lives.

11.1.3. Standard tax asset lives

The AER accepted our proposed standard tax asset lives. This is because they are consistent with those approved in the regulatory control period 2010-15 and the values prescribed by the ATO. However, it updated the standard tax asset life for the 'Equity raising costs' asset class to five years.

11.2. Stakeholder feedback

On our review, there was limited feedback from customers on corporate income tax. Cotton Australia called on the AER to closely examine the way it determines allowances for taxation equivalents and the like.[86]

11.3. Other influencing factors

There is an obvious link between arrangements for the TAB and the underlying RAB. Changes to capital expenditure and depreciation will influence outcomes. Our response to tax asset lives is

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[86] Cotton Australia, Op. cit, p12.

strongly influenced by our response to the AER's Preliminary Determination on regulatory depreciation (refer to Chapter 8).

11.4. Our response

We have revised our Regulatory Proposal for calculating tax remaining lives consistent with our revised approach to regulatory depreciation. Our revised approach is outlined in our revised Regulatory Proposal and set out in detail in section 4.2.4 of the supporting document *03.03.01 – (Revised) Building Block Components*. We also rely on additional evidence from Houston Kemp and have used a consistent approach for our tax asset remaining lives for our asset classes.

12. Efficiency Benefit Sharing Scheme

This section summarises our response to the AER's decision on the Efficiency Benefit Sharing Scheme (EBSS). The EBSS seeks to provide a financial incentive for Ergon Energy to improve the efficiency of our operating expenditure and to share any resulting efficiency gains (or losses) with our customers.

12.1. Preliminary Determination

12.1.1. Carryover amounts

Ergon Energy proposed a carryover revenue adjustment of $146.1 million relating to the operation of the EBSS in the regulatory control period 2010-15. The AER accepted our proposal to apply a carryover reward to our regulated revenue, but substituted its own value of $130.1 million. This is due to the removal of movements in provisions from the EBSS calculation. The AER did not consider that the increases in provisions reflect the actual cost incurred in delivering network services as they are a revised estimate based on assumptions.

12.1.2. Application in regulatory control period 2015-20

Ergon Energy proposed to apply the new EBSS in the regulatory control period 2015-20, in accordance with the Framework and Approach Paper. However, we contended that Ergon Energy should be able to exclude costs which would have qualified for a cost pass through.

The AER decided not to apply the EBSS in the regulatory control period 2015-20. The AER noted the linkage between the current version of the EBSS and the revealed costs approach to assessing operating expenditure. That is, if the incentive framework works effectively, the actual operating expenditure incurred in the base year should be representative of the efficient level; thus leading to the adoption of the base year revealed costs in the AER's operating expenditure forecast.

While the revealed costs approach will continue to be used to assess forecasts, the AER will test efficiency and adjust the forecast if it is inefficient. This places less weight on the revealed costs approach.

In Ergon Energy's case, the AER has determined that our operating expenditure is higher than that of a benchmark efficient service provider. Consequently, there is uncertainty around whether the AER will use the revealed costs from the regulatory control period 2015-20 when forecasting operating expenditure in the following period. If they are not used, the AER considers the EBSS should not apply.

12.2. Stakeholder feedback

A number of stakeholders do not support the application of the EBSS in the regulatory control period 2015-20.[87] The Alliance of Electricity Consumers and COTA Queensland also recommended the AER reject our proposed carryover revenue adjustment, on the basis that inefficient costs should be borne by the business and not be passed on to customers[88] and the previous operating expenditure

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[87] Alliance of Electricity Consumers, Op. cit, p29; Australians in Retirement – Cairns and Northern Districts Branch, Op. cit, p2; and Energy Users Association of Australia, Op. cit, p30.

[88] Alliance of Electricity Consumers, Op. cit, p29.

allowances were already over-generous.[89] The carryover revenue adjustment was also not supported by Townsville Enterprise.[90] Meanwhile, the Chamber of Commerce and Industry Queensland recommended the AER should negotiate targets that deliver genuine efficiency improvements and incentivise best practice.[91]

12.3. Our response

Ergon Energy has accepted the removal of movements in provisions from the EBSS calculation, as made by the AER in its Preliminary Determination. We have updated our Regulatory Proposal to reflect this change.

Ergon Energy disagrees with the AER's decision to not apply the EBSS in the regulatory control period 2015-20. Ergon Energy believes it was the intention of the Better Regulation Program that the EBSS and Capital Expenditure Sharing Scheme (CESS) work together to provide balanced expenditure incentives, across both operating expenditure and capital expenditure. Further, the AER's decision to not apply the EBSS pre-empts a decision on the efficiency or otherwise of our costs in the regulatory control period 2015-20. Our detailed response on the EBSS is contained in our supporting submission, *Incentive Schemes – Response*. We have also made changes to our Regulatory Proposal. Changes have been made in the following documents:

- Chapter 3 of our Regulatory Proposal
- *03.01.03 – (Revised) Application of Incentive Schemes.*

[89] COTA Queensland, Op. cit, p2.
[90] Townsville Enterprise (2015), *Submission to the QLD electricity distributors' regulatory proposals*, 30 January 2015, p4.
[91] Chamber of Commerce and Industry Queensland, Op. cit, p22.

13. Capital Expenditure Sharing Scheme

This section summarises our response to the AER's decision on the CESS. The CESS seeks to provide incentives to Ergon Energy to improve the efficiency of our capital expenditure allowance and to share any resulting efficiency gains (or losses) with customers.

13.1. Preliminary Determination

Consistent with the Framework and Approach Paper and our October Regulatory Proposal, the AER decided to apply version 1 of the CESS to Ergon Energy in the regulatory control period 2015-20. In our October Regulatory Proposal, we also suggested that the AER should consider the potential impacts on the operation of the CESS that may be generated by:

- Customer Connection Initiated Capital Works expenditure being above or below the expected AER allowances or forecasts
- decisions by Ergon Energy to not apply for pass throughs for events that may meet the threshold but generate capital costs that could contribute to over-expenditure of allowances.

Ergon Energy proposed that we should be able to seek an exclusion for these matters. The AER did not support this proposal. It did not consider there was sufficient evidence to allow exclusions for capital expenditure resulting from uncontrollable events. Specifically, the AER believed:

- there was no reason why underspends or overspends should be shared differently between Ergon Energy and customers in each regulatory year, or shared differently to other costs
- Ergon Energy would not always be penalised or rewarded under the CESS for underspends or overspends on Customer Connection Initiated Capital Works, as the CESS rewards and penalties are determined relative to the total forecast capital expenditure (not the category)
- Ergon Energy should take into account the issues we had raised, in terms of pass throughs, when making our expenditure decisions.

13.2. Stakeholder feedback

Similar to the EBSS, a number of stakeholders did not did not support the application of the CESS.[92]

13.3. Our response

Ergon Energy accepts the AER's Preliminary Determination to apply the CESS during the regulatory control period 2015-20. However, we have not revised our proposal for CESS. Ergon Energy does not agree with the AER's reasons for not allowing exclusions for capital expenditure associated with uncontrollable events. While we agree that the rewards and penalties are determined relative to total forecast capital expenditure, rather than at the category level, Ergon Energy believes costs that are uncontrollable should be excluded. This is because neither we nor customers should be penalised for expenditure that is outside our control.

Ergon Energy also notes that, in its Preliminary Determination, the AER decided not to apply the EBSS in the regulatory control period 2015-20. Ergon Energy disagrees with this position as outlined above. However, if the AER decides not apply the EBSS, Ergon Energy believes that the CESS should also not apply. This is consistent with the intent of the Better Regulation Program which was

[92] Alliance of Electricity Consumers, Op. cit, p29 and Australians in Retirement – Cairns and Northern Districts Branch, Op. cit, p2.

for the schemes to work together to provide balanced expenditure incentives, across both operating expenditure and capital expenditure.

Our detailed response on the CESS is contained in our supporting submission, *Incentive Schemes – Response.*

14. Service Target Performance Incentive Scheme

This section summarises our response to the AER's decision on the application of the Service Target Performance Incentive Scheme (STPIS) in 2015 to 2020. The STPIS rewards Ergon Energy when we improve our average service quality to customers and penalises us for a reduction in average service quality to customers.

14.1. Preliminary Determination

The AER generally accepted the positions put forward by Ergon Energy in relation to the STPIS. It did not accept our proposed performance targets or the VCR value (and hence, our proposed incentive rates).

14.1.1. Applicable components and parameters

Consistent with the AER's Framework and Approach Paper and our October Regulatory Proposal, the AER decided to:

- set performance targets for both System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) under the reliability of supply component
- divide our network into urban, short rural and long rural feeder types
- apply the telephone answering parameter under the customer service component
- not apply the Guaranteed Service Levels (GSL) component, given the operation of the jurisdictional GSL scheme.

14.1.2. Revenue at risk

The AER accepted our proposal to cap the revenue at risk at ± 2 per cent. Within this, there will be a cap of ± 1.8 per cent for the reliability of supply component and ± 0.2 per cent for the customer service component.

14.1.3. Reliability of supply component

Major event day exclusions

The AER accepted our proposal to calculate Major Event Day thresholds using the 2.5 beta method set out in appendix D of the national STPIS.

Performance targets

The AER accepted our approach to set performance targets based on historical averages, as well as our revised performance targets.[93] These performance targets set out in Table 9 below.

[93] The performance targets proposed in our October Regulatory Proposal were based on average historical performance that had been adjusted to take into account the expected reliability outcomes of our automatic circuit reclosers and remote control switch capital expenditure programs. The STPIS guideline only requires an adjustment if the expenditure was part of the reliability improvement program. Consequently, in April 2015, we submitted revised performance targets that did not include this adjustment.

Table 9: AER SAIDI and SAIFI performance targets, 2015-20

	Preliminary Decision
SAIDI	
Urban	126.73
Short rural	317.06
Long rural	742.47
SAIFI	
Urban	1.503
Short rural	3.019
Long rural	5.348

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 11 – STPIS*, April 2015, p8.

Incentive rates

The AER has applied the VCR value determined by AEMO in its recent review of the VCR,[94] rather than applying the VCR value prescribed in the national STPIS.

The incentive rates determined by the AER, using the AEMO VCR value and the smoothed annual revenue determined from its Preliminary Determination, are detailed in Table 10.

Table 10: AER incentive rates on reliability of supply targets

	Urban	Short rural	Long rural
SAIDI	0.01541	0.01538	0.00332
SAIFI	1.33964	1.75543	0.50072

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 11 – STPIS*, April 2015, p8.

14.1.4. Customer service component

Performance target

The AER has decided to apply our proposed performance target of 77.3 per cent of calls being answered in 30 seconds.

Incentive rate

The incentive rate for the telephone answering parameter will be -0.04 per cent.

14.2. Stakeholder feedback

Some stakeholders do not support the application of the STPIS.[95] For example, the Alliance of Electricity Consumers indicated that Ergon Energy is meeting our STPIS targets through our N-1 network planning obligations, rather than through innovative network management. They indicated that providing rewards for meeting legislative levels of service is not in the interests of consumers.[96]

QCOSS also suggested there is little evidence that customers, in aggregate, want improved reliability. QCOSS recommended the STPIS targets should be maintained at the current level in

[94] AEMO (2014), *Value of Customer Reliability Review, Final Report*, September 2014.
[95] Australians in Retirement – Cairns and Northern Districts Branch, Op. cit, p29; and QCOSS, Op. cit, pp95-96.
[96] Alliance of Electricity Consumers, Op. cit, p29.

2015-16 and reduce gradually to reflect the declines in reliability forecast by the Department of Energy and Water Supply.[97]

Another stakeholder also raised concerns that the application of the STPIS to the distribution network as a whole does not help customers experiencing localised reliability issues.[98] Rather, focus should be placed on feeders that are of strategic importance for industry development and employment, and encouraging generation.

Finally, the CCP recommended that the AER needs to negotiate targets that deliver genuine efficiency improvements and incentivise best practice.[99]

14.3. Other influencing factors

Ergon Energy has proposed a number of changes in our revised Regulatory Proposal that have impacted the smoothed annual revenue used by the AER to determine the incentive rates.

14.4. Our response

Ergon Energy generally accepts the AER's Preliminary Determination on the STPIS.

Ergon Energy has concerns with the use of AEMO's VCR figures. However, in the absence of other recent alternatives, Ergon Energy has applied these targets in our revised Regulatory Proposal. The performance targets have also been updated in our revised Regulatory Proposal to align with the AER's Preliminary Determination. We have recalculated the incentive rates contained in our October Regulatory Proposal in light of the new VCR and our revised smoothed annual revenue. These amendments have been made in our supporting document, *03.02.02 – (Revised) Proposed application of STPIS for the 2015/16 to 2019/20 regulatory control period*.

In the Preliminary Determination, the AER introduced a cap of ±1.8 per cent on the reliability of supply component of the STPIS.[100] The AER did not acknowledge that this was a change from how the STPIS is applied in the regulatory control period 2010-15, nor did it provide a reason for introducing this cap. Ergon Energy does not agree with the proposed change and believes it is inconsistent with the national STPIS.

The methodology outlined in the national STPIS caps the S-factor adjustment for customer service parameters at 0.2 per cent and the overall S-factor adjustment at 2.0 per cent. Neither the national STPIS or the Framework and Approach Paper apply a cap to the reliability of supply S-factor. Therefore, Ergon Energy has retained our position in the revised Regulatory Proposal.

All other elements of our STPIS proposal remain unchanged.

Regarding the feedback from stakeholders, Ergon Energy notes that we are no longer subject to deterministic N-1 security standards. Further, our STPIS performance targets for the regulatory control period 2015-20 will be set with reference to our historical performance, not legislated levels of service. We continue to be subject to Minimum Service Standards (MSS) set by the Queensland Government. However, the MSS operates outside of the STPIS and does not impact any reward (or penalty) that Ergon Energy incurs under the STPIS.

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[97] QCOSS, Op. cit, pp95-96.
[98] Cummings Economics, Op. cit, pp25-26.
[99] Hugh Grant (CCP Member), Op.cit.
[100] AER, *Preliminary Decision Ergon Energy Determination 2015-16 to 2019-20, Attachment 11 – Service Target Performance Incentive Scheme*, April 2015, p.11-7.

While the STPIS provides an incentive to improve our average level of reliability over time, this is tempered by the need to demonstrate that our reliability program is prudent, efficient and meets our customers' expectations. The customer engagement we undertook as part of the development of our forecast works program demonstrates that reliability of supply remains an important factor for our customers, but that they are not necessarily willing to pay for improvements in that reliability.

Ergon Energy does not believe performance targets for reliability of supply should be reduced over time in line with the MSS requirements, as this will make it easier for Ergon Energy to outperform, thereby earning a reward which will increase the prices paid by our customers. This is inconsistent with our customers' expectations more generally. Setting the reliability of supply targets based on historical performance means that the targets will move over time to reflect those customer expectations.

Ergon Energy also notes the concerns of some stakeholders that the STPIS does not address reliability performance at the feeder level, and agrees with the AER that this is a matter regarding the design of the incentive scheme rather than the application of the STPIS to Ergon Energy specifically. However, we note that we have proposed to continue our Worst Performing Feeder Improvement Program in the regulatory control period 2015-20 to address localised performance issues. Further information on this program is provided in *07.00.05 – (Revised) Reliability & Quality of Supply Expenditure Forecast Summary.*

Our detailed response to the AER's preliminary decision on the STPIS is contained in *Incentive Schemes – Response*.

15. Demand Management Incentive Scheme

This section summarises our response to the AER's decision on the application of the Demand Management Incentive Scheme (DMIS) in 2015 to 2020. The DMIS seeks to provide incentives to Ergon Energy to implement efficient non-network alternatives for managing expected demand on the network and efficiently connect embedded generators.

15.1. Preliminary Determination

The AER has determined to continue to apply the Demand Management Innovation Allowance (DMIA). The innovation allowance amount will be $1 million per annum (real $2014-15).

15.2. Stakeholder feedback and other factors

There is mixed support for demand management incentives. The following organisations support the use of incentives:

- The Far North Queensland Regional Organisation of Councils recommended having incentives to manage demand during peak times, to better manage capital expenditure and utilisation.[101]
- SPA Consulting Engineers suggested the AER work with Ergon Energy to increase incentives for demand side control, specifically additional funding for initiatives to increase load factor.[102]

On the other hand, the Australians in Retirement organisation does not support incentives[103] and the Local Government Association of Queensland (LGAQ) believes the AER should carefully consider proposed demand management initiatives in light of existing off-grid solutions.[104] While supportive of demand management incentives, the Total Environment Centre was disappointed that information on our proposed DMIA activities was not available and was concerned that Ergon Energy would not spend the entire DMIA.[105]

15.3. Our response

The AER's position in relation to the DMIS is consistent with the approach in our October Regulatory Proposal and, as such, we accept the AER's decision on this matter. Ergon Energy has not made any revisions to our proposal.

Consistent with the Preliminary Determination, we have included the DMIA as an individual line item within the revenue adjustment section of the PTRM.

We note stakeholder concerns regarding demand management incentives. Like the AER, we consider the long-term benefits of the scheme outweigh the minimal price increases. DMIA projects funded in the regulatory control period 2010-15 have provided some valuable insights and knowledge, and created the opportunity to move innovation from concept to business as usual.[106] Some examples of initiatives we have undertaken using this scheme include:

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[101] Far North Queensland Regional Organisation of Councils, Op. cit, p7.
[102] SPA Consulting Engineers (QLD) Pty Ltd (2015), Op. cit, p3.
[103] Australians in Retirement – Cairns and District Branch, Op. cit, p2.
[104] LGAQ (2015), *Submission in response to the AER's Issues Paper*, 30 January 2015, p1.
[105] Total Environment Centre, Op. cit, p13.
[106] Further information on the outcomes of DMIA funded projects can be found at https://www.ergon.com.au/network/network-management/demand-management/demand-management-plans-and-reports.

- Development and trialling of a network device that supports dynamic control of reactive power to enable higher penetration of renewable energy systems while maintaining a stable power quality.
- Trial to engage directly with builders earlier in the building construction cycle in order to inform customers and builders about energy efficiency and peak demand for the purposes of reducing the peak demand impacts on the network.
- Developing and trialling a system that interacts with our customers dynamically to modify their energy use patterns for the purposes of reducing demand on peak days.

In relation to LGAQ’s comments, Ergon Energy notes that all nominated DMIA projects are subject to screening and feasibility processes, consistent with the AER’s DMIS, and a subsequent cost-benefit analysis is undertaken to identify the highest value projects, based on factors including their ability to shape energy load profiles and gain community and customer acceptance.

16. Classification of services

This section summarises our response to the AER's decision on the classification of services. Service classification is the process of determining which distribution services are to be subject to economic regulation under the NER and what form that regulation will take (i.e. direct, light handed or no regulatory oversight).

16.1. Preliminary Determination

The AER decided to apply the classification of services set out in its Framework and Approach Paper, with the following exceptions:

- The AER decided to classify separate Type 5 and 6 metering services for:
    - meter reading and maintenance
    - meter provision before 1 July 2015
    - meter provision after 1 July 2015.
- The AER clarified that load control services provided by equipment external to a Type 5 or 6 meter is a Standard Control Service, while load control services provided by equipment internal to the meter is an Alternative Control Service.
- The undersea cable that connects Hayman Island to mainland Australia continues to be an unregulated asset. Ergon Energy proposed to include this in our RAB from 1 July 2015.

Each of these changes is discussed below.

16.1.1. Exit fees

A meter exit fee was initially included in the classification of services as an Auxiliary Metering Service. It was intended to recover the cost of stranded asset costs associated with the removal of a meter(s) from a customer's premises before the end of its useful life at the request of the customer (or customer's retailer) due to a change in the Responsible Person. Accordingly, our October Regulatory Proposal included a Customer Transfer fee to recover the residual capital costs and administrative costs associated with the removal of a meter.

The AER considers our Customer Transfer fee would present a significant barrier to customers wishing to switch to an alternative metering provider and inhibit competition. Therefore, it decided to:

- recover the residual capital value through a separate Alternative Control Service
- not classify an exit fee service (i.e. we are not able to charge administrative costs).

16.1.2. Residual meter value

To allow the recovery of residual capital costs and operating costs, the AER's Preliminary Determination classified the following Alternative Control Services:

- Type 5 or 6 meter reading and maintenance – recovers operating costs incurred by Ergon Energy in operating a meter. This cost would be avoided if a customer switches to an alternative metering provider
- Type 5 or 6 meter provision (pre 1 July 2015) – recovers the cost of meters installed before 1 July 2015

- Type 5 or 6 meter provision (post 1 July 2015) – recovers the cost of meters installed on or after 1 July 2015.

16.1.3. Load control

The AER has amended some descriptions in the ‘Network Services’ and ‘Auxiliary Metering Services’ service groupings to reflect its intention that load control equipment outside of the meter is a Standard Control Service and load control provided by the meter itself is an Alternative Control Service.

16.1.4. Hayman Island

As noted above, the AER has decided to retain an unregulated classification for the Hayman Island undersea cable. In reaching this conclusion, the AER considered the matters set out in clause 6.2.1(c) of the NER, as well as the customer’s desire for the current connection agreement to continue and for the undersea cable to remain unregulated.

The AER noted commercial discussions between the parties are continuing. Therefore, the AER will reconsider its approach in the Substitute Determination.

16.2. Stakeholder feedback and other factors

Since submitting our October Regulatory Proposal, Ergon Energy has continued discussions with Hayman Island. Based on those discussions, the parties have agreed to treat the undersea cable as an unregulated asset for the regulatory control period 2015-20. Therefore, Ergon Energy has amended our revised Regulatory Proposal to reflect that agreement.

16.3. Our response

Ergon Energy generally accepts the AER’s classification of services. Ergon Energy is concerned with the AER’s decision in relation to Default Metering Services. However, given system changes have already been made to implement them, Ergon Energy has included this treatment in our revised Regulatory Proposal. Ergon Energy’s concerns with Default Metering Services are set out in our supporting submission *Metering – Response.*

There are also a few inconsistencies in the classification of services which need to be addressed by the AER. Specifically:

- The AER has not removed the meter exit fee from Auxiliary Metering Services, despite its decision to not apply an exit fee.
- Type 5 and 6 data services have been included in two different services:
    - Type 5 and 6 meter installation and data services
    - Type 5 and 6 metering maintenance, reading and data services.

  Ergon Energy considers the former service should be removed and the service description relating to data services should be included in the metering maintenance etc. service.
- The description of meter installation should be included in the Type 5 and 6 meter provision (after 1 July 2015) service description and the service should be renamed to include installation (i.e. ‘Type 5 and 6 meter installation and provision (after 1 July 2015)’).

Further, we note the AER’s clarification regarding load control services is consistent with our understanding of the classification of services set out in the Framework and Approach Paper.

Ergon Energy has updated the October Regulatory Proposal and *02.01.01 – (Revised) Classification Proposal* to reflect these issues, along with some minor adjustments to ensure consistency with the AER's Preliminary Determination.

17. Control mechanism for Standard Control Services

This section summarises our response to the AER's decision on the control mechanism for Standard Control Services.

17.1. Preliminary Determination

17.1.1. Application of the revenue cap

Consistent with the Framework and Approach Paper and our October Regulatory Proposal, the AER decided to apply a revenue cap to Standard Control Services. The revenue cap for any given year is the Total Annual Revenue (TAR) plus any adjustment required to move the DUOS unders and overs account to zero.

The AER accepted our proposal to include:

- the final carryover amount for the 2010-15 DMIS in the incentive scheme adjustment
- the under- or over-recoveries relating to capital contributions and shared assets from 2013-14 and 2014-15 in the B-factor
- FiT cost pass through amounts relating to 2013-14 and 2014-15 in the C-factor
- amounts relating to the occurrence of our prescribed and nominated pass through events in the C-factor.

However, the AER did not accept our proposal to include:

- the annual adjustment for the STPIS in the incentive scheme adjustment. Instead, the AER included this adjustment in the calculation of AR_t
- the DUOS under- and over-recovery adjustments in the B-factor. Consistent with the regulatory control period 2010-15, this will occur outside of the TAR formula
- other one-off revenue adjustments approved by the AER in the C-factor. The AER considers that a general 'catch all' definition is not consistent with incentive regulation and increases uncertainty and administration costs in the annual pricing proposals.

In its Preliminary Determination, the AER also decided to deal with changes to revenue resulting from the annual return on debt update through the X-factors.

17.1.2. Under and over recovery mechanism for DUOS

The AER decided to apply an unders and overs mechanism, consistent with the approach taken in the regulatory control period 2010-15 and our October Regulatory Proposal.

Our October Regulatory Proposal also included a principles-based approach to tolerance limits. The AER did not approve the use of tolerance limits in its Preliminary Determination. Rather, it expects the closing balance of the DUOS unders and overs account in year t must be zero. The AER stated the risks of applying tolerance limits, such as delayed price shocks and reduced cost reflectivity in prices, outweigh the benefits of potentially smoothing prices.

Ergon Energy must demonstrate compliance with the DUOS unders and overs account set out in Appendix A of Attachment 14 of its Preliminary Determination in our annual Pricing Proposal.

17.1.3. Under and over recovery mechanism for TUOS

Similar to DUOS, the AER decided to apply an unders and overs mechanism for TUOS. Consistent with the regulatory control period 2010-15, the AER requires the closing balance of the TUOS unders and overs account in year t to be zero.

Ergon Energy must demonstrate compliance with the TUOS unders and overs account set out in Appendix B of Attachment 14 of its Preliminary Determination in our annual Pricing Proposal.

Chumvale and Powerlink charges

In our October Regulatory Proposal, we proposed to recover charges associated with the use of the Chumvale and Powerlink lines through our operating expenditure allowance. However, the AER considers these charges should continue to be recovered as designated pricing proposal charges. Specifically, the AER indicated the use of the Chumvale and Powerlink lines are 'prescribed exit services', which are included in the NER definition of designated pricing proposal charges.

The AER also suggested that the non-prescribed Powerlink connection services are already prescribed.

17.1.4. Reporting on jurisdictional scheme amounts

Ergon Energy proposed to apply a two year lag to the recovery of costs associated with FiT payments made under the Queensland Government Solar Bonus Scheme. In terms of reporting, we proposed to set out in our annual Pricing Proposal:

- the jurisdictional scheme amounts that we will recover from customers for the relevant regulatory year
- how those amounts will be passed on to our customers.

We proposed that actual FiT payments made in year t would be recovered in year t+2. The amount to be recovered would be adjusted for the time cost of money by applying the relevant WACC for the two years of the lag between when we incur the cost and when we recover those costs from our customers.

The AER did not accept our proposed method of reporting on the jurisdictional scheme amounts, as it rejected our proposed two year lag approach. The AER considered this approach to be a significant departure from the national approach to the recovery of jurisdictional scheme amounts and is also not consistent with the NER's emphasis on cost-reflective pricing. Instead, the AER requires Ergon Energy to provide a jurisdictional scheme unders and overs account in our annual Pricing Proposal. This account is set out in Appendix C of Attachment 14 of its Preliminary Determination.

The AER requires the closing balance of the jurisdictional schemes unders and overs account in year t to be zero.

17.1.5. Side constraints

For each year after 2015-16, the AER determined to apply side constraints to the weighted average revenue to be raised from each tariff class. The permissible percentage increase is the greater of CPI-X plus 2 per cent or CPI plus 2 per cent. Recovery of certain revenues such as those to accommodate cost pass throughs is disregarded in deciding whether the permissible percentage has been exceeded.

17.1.6. Assigning retail customers to tariff classes

The AER considered our October Regulatory Proposal contained an effective system for assessing and reviewing the basis on which a customer is charged. However, the AER amended our procedures for assigning and reassigning retail customers to tariff classes to ensure retail customers are referred to the Queensland Energy and Water Ombudsman if they disagree with the assignment or reassignment (to the extent the resolution is within the Ombudsman's jurisdiction).

17.2. Stakeholder feedback and other influencing factors

Ergon Energy noted limited stakeholder feedback on our control mechanism. The Chamber of Commerce and Industry Queensland did not support the recovery of FiT costs from customers. Rather any payments made should be absorbed by Ergon Energy.[107] They also suggested it may be appropriate to alter the recovery arrangements. COTA Queensland and the Queensland Farmers' Federation supported the two year delay in the recovery of FiT payments.[108]

As noted in Section 3.1.2, the AER wrote to Ergon Energy informing us of an error in the revenue cap formula set out in the Preliminary Determination. The AER's letter advised that the parameter for DUOS under/over-recoveries from previous years was not included in the formula, when it should have been. Consequently, the AER required us to include a $DUoS_t$ component in the revenue cap formula when submitting our 2015-16 Pricing Proposal and indicated that it would fix the error in the Substitute Determination.

Based on correspondence to other NSPs,[109] Ergon Energy understands the AER is likely to expect Ergon Energy to demonstrate in our annual Pricing Proposals that our revenues are consistent with the formulae set out below:

1 $$AR_t = AR_{t-1}(1+\Delta CPI_t)(1-X_t)(1+S_t)$$

2 $$TAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$$ i=1,...,n and j=1,...,m and t=1,...,5

3 $$TAR_t = AR_t \pm I_t \pm B_t \pm C_t \pm DUoS_t$$

Where:

AR_t is the annual smoothed expected revenue for regulatory year t. For the first year of the 2015-20 regulatory control period, this amount will be equal to the smoothed revenue requirement for 2015-16 set out in the PTRM.

ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics (ABS) CPI All Groups, Weighted Average of Eight Capital Cities from December in year t–2 to December in year t–1. For example, for the 2015-16 year, t-2 is December 2013 and t-1 is December 2014 and in the 2016-17 year, t-2 is December 2014 and t-1 is December 2015 and so on

X_t is the X-factor for each year of the 2015-20 regulatory control period as determined in the PTRM, and annually revised for the return on debt update in accordance with the formula specified in the return on debt appendix I calculated for the relevant year

S_t is the STPIS factor sum of the raw s-factors for all reliability of supply and customer service parameters (as applicable) to be applied in year t

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[107] Chamber of Commerce and Industry Queensland, Op. cit, p7 and p15.
[108] COTA Queensland, Op. cit, p3; and Queensland Farmers' Federation, Op. cit, p4.
[109] See, for example, AER (2015), *Letter to Mr Vince Graham (Chief Executive Officer, Ausgrid)*, 20 May 2015.

TAR_t is the total annual revenue in year t

p_t^{ij} is the price of component i of tariff j in year t

q_t^{ij} is the forecast quantity of component i of tariff j in year t

I_t is the final carryover amount from the application of the DMIS from the 2010-15 distribution determination. This amount will be deducted from/added to allowed revenue in the 2016-17 pricing proposal

B_t is any under or over-recoveries relating to capital contributions and shared assets from 2013-14 and 2014-15

C_t is the sum of adjustments related to:

- feed-in tariff cost pass through amounts relating to 2013-14 and 2014-15
- amounts relating to the occurrence of any of the prescribed and nominated cost pass through events

$DUoS_t$ is an annual adjustment related to the balance of the DUoS unders and overs account with respect to regulatory year t.

17.3. Our response

Ergon Energy does not agree with several aspects of the AER's Preliminary Determination on the control mechanism applying to Standard Control Services. Our key concerns are outlined in the sections below and relate to:

- the revenue cap formula
- the under and over recovery mechanism for DUOS
- the recovery of jurisdictional scheme amounts
- assigning and reassigning retail customers to tariff classes.

We have revised our Regulatory Proposal in relation to the AER's Preliminary Determination on Chumvale and Powerlink charges. We note the AER's interpretation and application of the NER and have treated these charges as designated pricing proposal charges in the regulatory control period 2015-20. These changes have been reflected in:

- Chapter 4 of our Regulatory Proposal
- *01.01.02 – (Revised) Effect of Transitional Arrangements*
- *04.01.00 – (Revised) Compliance with Control Mechanisms*
- *04.01.05 – (Revised) Control Mechanism Model*.

Our detailed response on the control mechanism is contained in our supporting submission, *SCS Building Blocks, Control Mechanism and Pricing – Response.*

17.3.1. Application of the revenue cap

Ergon Energy has not applied the revenue cap formula contained in the Preliminary Determination. The reason for this is twofold:

- The AER has not provided any justification for a departure from the formula set out in the Framework and Approach Paper in its decision, as required by the NER.[110] Ergon Energy liaised extensively with the AER at the time of the Framework and Approach and we do not believe there is any reason to depart from the Framework and Approach formula unless an error has been made.
- The revenue cap formula contained in the Preliminary Determination cannot be applied in practice due to the error identified in relation to the DUOS under/over-recoveries.

We also consider the inclusion of the S-factor in the AR_t calculation is unnecessarily complex and administratively burdensome.

Ergon Energy has applied the revenue cap formula contained in the Framework and Approach Paper, with the following adjustments:

- We have replaced the equal sign in the second total allowed revenue formula with a greater than or equal to sign (i.e. $TR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_{ij}^{t} q_{ij}^{t}$). This is because it is difficult for the expected revenue to be recovered from all customers via tariffs to exactly equal the revenue cap (e.g. due to rounding of rates or in circumstances where revenues (and prices) are required to be adjusted to satisfy side constraints).
- We have amended the formula component descriptions to reflect our original positions in relation to DUOS under/over recoveries, the S-factor and other one-off revenue adjustments, as well as terminology used by the AER in its Preliminary Determination (where appropriate).

Our position on the revenue cap formula also necessitates changes to the side constraints formula proposed by the AER.

Changes have been made in the following documents:

- Chapter 4 of our Regulatory Proposal
- *04.01.00 – (Revised) Compliance with Control Mechanisms*
- *04.01.05 – (Revised) Control Mechanism Model*.

17.3.2. Under and over recovery mechanism for DUOS

We maintain that a principles-based approach to tolerance limits should apply as per the October Regulatory Proposal. The AER has adopted smoothing arrangements at the beginning of the regulatory control period 2015-20 to minimise the impact for customers. We see no reason why a smoothing approach within a regulatory control period should be rejected.

If tolerance limits are not allowed, Ergon Energy proposes that the DUOS unders and overs reconciliation incorporate the carry forward of t-2 actuals and t-1 estimates into the overs and unders adjustment in year t. We understand a similar approach has been adopted in NSW. Details of our revised approach can be found in our supporting submission *SCS Building Blocks, Control Mechanism and Pricing – Response.*

We have also amended our proposal for TUOS under and over-recoveries so that it is consistent with our revised proposal for DUOS under and over-recoveries.

We have also revised the following documents:

- Chapter 4 of our Regulatory Proposal

[110] NER, clause 6.12.3(c1).

- *04.01.00 – (Revised) Compliance with Control Mechanisms*
- *04.01.01 – (Revised) Designated Pricing Proposal Charges*
- *04.01.05 – (Revised) Control Mechanism Model*.

17.3.3. Reporting on jurisdictional scheme amounts

There is no basis for the AER's reasoning to reject a two-year lag on jurisdictional scheme amount recovery.

Clause 6.18.7A of the NER prescribes a number of requirements that must be satisfied in relation to the recovery of jurisdictional scheme amounts in a pricing proposal.

The first of these is the requirement, under clause 6.18.7A(a) of the NER, that a pricing proposal must provide for tariffs designed to pass on to customers a DNSP's jurisdictional scheme amounts for approved jurisdictional schemes. The framework proposed by Ergon Energy will satisfy this requirement, in that it will produce tariffs that are designed to pass on to customers Ergon Energy's costs under the Solar Bonus Scheme. Clause 6.18.7A(a) of the NER is silent as to the year in which those costs must be passed on to customers. The limitations that apply to the passing on of these costs in a particular year are to be found in clause 6.18.7A(b) of the NER.

The second is the requirement under clause 6.18.7A(b) of the NER that the amount to be passed on to customers for a particular regulatory year *must not exceed* the estimated amount of the costs under the jurisdictional scheme, adjusted for over or under recovery in accordance with clause 6.18.7A(c). This clause is critical, since it speaks of a pricing proposal providing for the recovery of the estimated costs under a jurisdictional scheme in the coming regulatory year, with an adjustment (or 'true up') for over or under recovery of costs in a previous year.

However, this clause provides, in express terms, only that the amount to be passed on to customers for a particular year 'must not exceed' the sum of the estimated amount and the under or over adjustment. It does not require that the amount to be passed on equates to the sum of the estimated amount and the over or under recovery amount. This is a critical point, since the proposed framework, under which Ergon Energy will not seek to recover any part of our estimated Solar Bonus Scheme costs in the relevant year, will ensure that the amount we seek to pass through to customers in our pricing proposal will never exceed the limit established by clause 6.18.7A(b) of the NER.

It is apparent from the drafting of clause 6.18.7A of the NER that the method for determining the over and under recovery amount, referred to in clause 6.18.7A(c) of the NER, is central to the operation of Ergon Energy's proposed framework.

In 2011, clause 6.18.7A of the NER was amended to give greater flexibility to the AER in determining the method by which the 'true up' would be calculated.[111] In its report explaining its reasons for these amendments, the Australian Energy Market Commission (AEMC) stated:

> "…the Commission noted that there are significant differences in the current true-up adjustment methodology between DNSPs. This means that the prescribed level of detail in the draft Rule for the true-up provision will be difficult for DNSPs to implement and lead to consequential differences with current practices which may make DNSPs either worse off or better off.

[111] See *National Electricity Amendment (DNSP Recovery of Transmission-related Charges) Rule*, Rule 2011 No 1.

On balance, the Commission considers that there is a need for a consistent approach and that a high level principles-based approach can achieve this. This approach will allow the AER and DNSPs the flexibility and clarity to determine how to make true-up adjustments." [112]

The critical word in this passage is 'flexibility'. The AEMC intended that a DNSP would have the flexibility to propose, and the AER would have the flexibility to approve, any suitable method for determining how to make true-up adjustments, provided that it satisfies the principles laid down in clause 6.18.7A(c) of the NER. This feature of the regime, coupled with the requirement that the amount to be passed through under the pricing proposal not exceed the limit established by clause 6.18.7A(b) of the NER, supports the alternative framework proposed by Ergon Energy.

Our proposed approach is also consistent with the pass through arrangements the AER adopted in its 2010-15 Distribution Determination. If the AER had legitimate concerns with what Ergon Energy is now proposing, it would never have adopted the regime it currently has in the first place.

There is also considerable precedent in other elements of the determination where recovery is only made on the actual audited financial information. We provide additional information on why the AER's decision is incorrect in our supporting submission.

17.3.4. Assigning retail customers to tariff classes

Ergon Energy supports many aspects of the AER's proposed procedures for assigning and reassigning retail customers to tariff classes as outlined in Appendix D of Attachment 14 of the Preliminary Determination. However, there are a few issues which we believe the AER needs to further consider, including:

- the mismatch between the AER's reasons for the preliminary decision and the procedures themselves, in terms of who the DNSP must notify of the assignment or reassignment and the availability of the dispute resolution mechanism
- the misuse of the term 'customer's retailer' in some sections of the procedures
- the appropriateness of notifying retailers in writing of the tariff class to which a customer has been assigned or reassigned, in the case of Alternative Control Services
- the impact and suitability of the requirement to make adjustments to prices as part of the next annual review of prices, in the event that a customer's objection to a tariff assignment is upheld by an external dispute resolution body.

We also note the Queensland Energy and Water Ombudsman is unable to investigate assignment and reassignment objections under the *Energy and Water Ombudsman Act 2006.* Therefore, section 7b of the procedures is not applicable in Queensland.

Our submission, *SCS Building Blocks, Control Mechanism and Pricing – Response*, provides further information on these issues.

[112] AEMC (2011), *DNSP recovery of transmission-related charges, Rule Determination*, AEMC, 24 March 2011, pp37-38.

18. Pass through events

To ensure DNSPs are able to recover the legitimate costs of unpredictable, high cost events that are beyond their control, the NER includes a cost pass through mechanism. In addition to a number of pre-defined events set out in clause 6.6.1(a1) of the NER, DNSPs are able to nominate events for approval through the regulatory determination process. This section summarises our response to the AER's decision on our nominated pass through events.

18.1. Preliminary Determination

Ergon Energy nominated five pass through events in our October Regulatory Proposal. The AER, in its Preliminary Determination, decided to:

- change the definition of our proposed natural disaster and insurance cap events
- rename our proposed insurance event to an insurer's credit risk event and change the definition
- not accept the retail separation and isolated network separation events because the event is likely to be captured by the prescribed regulatory change event.

18.2. Stakeholder feedback and other influencing factors

Canegrowers Isis Ltd did not support our proposal to nominate additional pass through events.[113] In addition, the Far North Queensland Regional Organisation of Councils did not support the retail separation event, citing that these costs should be borne by the business / its shareholder.[114] However, the Energy Users Association of Australia supported the pass through events, on the provision that the AER made significant cuts to our operating and capital expenditure forecasts.[115]

The announcement by the Queensland Government to merge Ergon Energy, Energex and Powerlink may materially change our costs in delivering Direct Control Services. A new merger event has therefore been proposed.

18.3. Our response

Ergon Energy agrees with the AER's decision to accept the natural disaster and insurance cap events. We generally accept the definitions proposed by the AER, but propose the re-inclusion of 'cyclone' in the natural disaster event definition. We also accept the AER's decision to replace the proposed insurance event with an insurer's credit risk event. We have made these changes in our supporting document, *04.01.03 – (Revised) Nominated cost pass through events*.

We do not accept the AER's decision to reject the retail separation and isolated network separation events. As such, we have retained these events in our revised Regulatory Proposal and our supporting document.

We have also proposed a new merger event. Our supporting document, *04.01.03 – (Revised Nominated cost pass through events*, provides further details on this event.

Ergon Energy notes stakeholder feedback received on our nominated pass through events. We consider that the cost pass through mechanism is the most appropriate mechanism to mitigate risks

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[113] Canegrowers Isis Ltd, Op. cit, p3.
[114] Far North Queensland Regional Organisation of Councils, Op. cit, p7.
[115] Energy Users Association of Australia, Op. cit, p4.

associated with these events. We believe it is in our customers' interests to pay for these types of events only if and when they happen, rather than through upfront capital and operating expenditure allowances.

This is because:

- if the event does not occur or the effects are less costly than expected, customers would be paying higher network prices than needed
- if the impact is worse than anticipated, Ergon Energy's financial viability may be at risk, affecting our ability to provide safe, secure and reliable distribution services to our customers.

With respect to the retail separation event, if such an event were to occur, it would result in an increase in the cost of providing Direct Control Services, for example through changes in the allocation of shared costs. These are costs that Ergon Energy would otherwise have incurred if we were a stand-alone distributor. In accordance with the NER, it is appropriate that Ergon Energy recover these costs from customers and not be borne by our shareholder.

Our detailed response is contained in *Pass Through Events – Response*.

19. Alternative Control Services

This section summarises our response to the AER's decision on our Alternative Control Services. Alternative Control Services are subject to direct controls on revenue and price. Many of these services are requested by, or relate to, a specific customer, and therefore the customer directly benefiting from the service is either charged a fixed fee or a quoted price for the service. Other services relate to a particular asset or class of assets that can be distinguished from the mesh distribution network (i.e. metering and public lighting services).

19.1. Ancillary network services

19.1.1. Preliminary Determination

Control mechanism

Consistent with the Framework and Approach Paper and our October Regulatory Proposal, the AER has applied caps on the prices of individual services to ancillary network services.[116]

For fee based services, the AER set a schedule of prices for the first year. For the following years, the previous year's prices are adjusted by CPI and an X-factor. The form of control for fee based services is:

$$p_i^t = p_i^{t-1}(1 + \Delta CPI_t)(1 - X_i^t) + A_i^t$$

Where:

p_i^{t-1} is the cap on the price of service i in year t–1

p_i^t is the cap on the price of service i in year t. However, for 2015-16 this is the price as determined in Table 16.20 of Attachment 16 of the Preliminary Determination

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t-1. For example, for the 2015-16 year, t-2 is December 2013 and t-1 is December 2014 and in the 2016-17 year, t-2 is December 2014 and t-1 is December 2015 and so on

X_i^t is the X-factor for service i in year t as set out in Table 16.1 of Attachment 16 of the Preliminary Determination

A_i^t is zero.

For quoted price services, the AER capped the input prices. The form of control for quoted price services is:

$$Price = Labour + Contractor\ Services + Materials + Capital\ Allowance$$

Where:

Labour consists of all labour costs directly incurred in the provision of the service which may include but is not limited to labour on-costs, fleet on-costs and overheads. Labour is escalated annually by $(1 - X_i^t)(1 + \Delta CPI_t)$.

[116] Our proposal refers to these services as 'Other Alternative Control Services'.

Contractor Services reflects all costs associated with the use of external labour including overheads and any direct costs incurred. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred are passed on to the customer. Contractor services are escalated annually by ΔCPI.

Materials reflect the cost of materials directly incurred in the provision of the service, material storage and logistics on-costs and overheads. Materials are escalated annually by ΔCPI.

Capital Allowance represents a return on and return of capital for non-system assets.

Fee based services

The AER approved the majority of Ergon Energy's proposed prices for fee based services. Our various application fees were not approved, as the AER found the proposed labour rates for administration employees (an input into the price) to be inefficient. It substituted our labour rate with a maximum allowed total labour rate of $73.90 (real $2014-15).

Quoted services

In line with its decision on fee based services, the AER determined that the administration labour rate was inefficient and substituted its own labour rate. No other changes were made to the cost inputs used in the calculation of indicative quoted prices for 2015-16.

On-costs

The AER considered that a maximum on-cost rate of 43.5 per cent should apply for the regulatory control period 2015-20.

Overheads

The AER determined that a maximum overhead rate of 65 per cent should apply in the regulatory control period 2015-20. The AER considered that maximum total labour rates which use this overhead rate are prudent. It also allows Ergon Energy with a reasonable opportunity to recover at least our efficient costs.

19.1.2. Other influencing factors

Ergon Energy has updated forecast inflation rates and escalators to reflect new data provided by Jacobs. We have also revised our operating and capital expenditure overhead rates.

As noted in Section 3.1.2, the AER wrote to Ergon Energy advising us that the quoted services formula contained two errors in relation to the descriptions of Contractor Services and Materials. That is, the formula indicated that these components should be escalated annually by ΔCPI.

Ergon Energy submitted revised 2015-16 prices as part of our 2015-16 Pricing Proposal. These prices reflected changes to the inflation rate, overhead rates and a correction to an oversight in the AER's Preliminary Determination. The AER approved our Pricing Proposal on 12 June 2015.

19.1.3. Our response

Ergon Energy accepts many aspects of the AER's decision on fee based services and quoted services. This includes:

- the application of a price cap form of control

- the setting of a schedule of prices for 2015-16 for fee based services, followed by the application of the price cap formula in the remaining years of the regulatory control period 2015-20
- the use of a cost build-up formula for quoted services
- the decision to remove “are escalated annually by ΔCPI” from the descriptions of Contractor Services and Materials in the quoted services formula
- the capping of labour for quoted services at the base labour rate (i.e. the capping does not apply to on-costs (including fleet on-costs) and overhead rates)
- the change to the base administration labour rate
- the application of a maximum overhead rate of 65 per cent
- the application of a maximum labour on-cost rate of 43.5 per cent.

However, we seek clarification from the AER on the following matters:

- the calculation of the X-factors applying to labour. The AER suggests the labour escalators are acting as defacto X-factors, but it did not provide updated labour escalators in the fee based and quoted services models
- the maximum labour on-cost rate. It appears the AER has incorrectly applied 43.33 per cent to the administration labour rates in the fee based and quoted services models. We corrected this in our 2015-16 Pricing Proposal, which was approved by the AER.

We have updated our October Regulatory Proposal to reflect:

- the 2015-16 prices approved by the AER in our 2015-16 Pricing Proposal
- updated inputs, including overhead rates, forecast inflation and escalators
- eight new fee based services for the installation and provision of Type 5 and 6 meters on or after 1 July 2015 (during business hours) (refer to Section 19.2.4)
- one new quoted service for the installation and provision of Type 5 and 6 meters on or after 1 July 2015 (after hours) (refer to Section 19.2.4)
- minor changes to the descriptions of some formula components, to improve clarity.

These changes have been made in:

- Chapter 5 of our Regulatory Proposal
- *05.05.01 – (Revised) Inputs and assumptions for Alternative Control Services*
- *05.06.01 – (Revised) ACS Pricing Inputs*
- *05.06.02 – (Revised) Fee based services model*
- *05.06.03 – (Revised) Quoted services model*.

Our detailed response on fee based and quoted services is contained in *Alternative Control Services – Other – Response*.

19.2. Metering

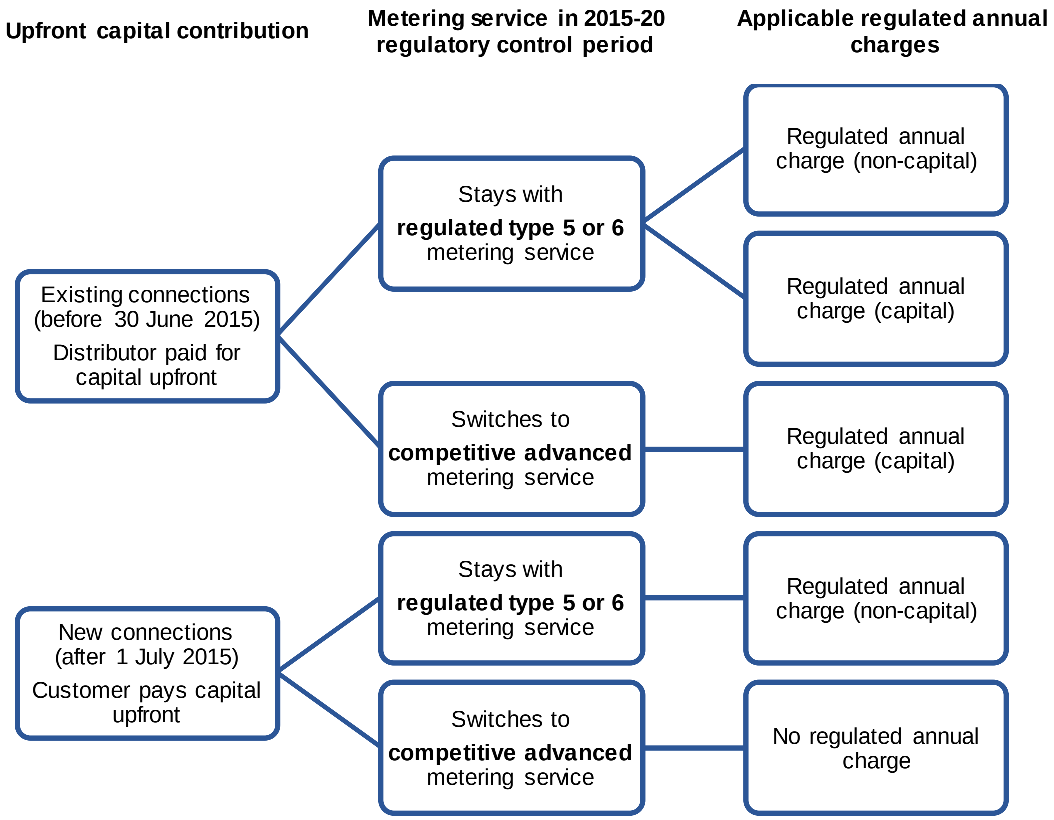
19.2.1. Preliminary Determination

In line with its Framework and Approach Paper, the AER classified Type 5 and 6 metering installation, provision, maintenance, reading and data reading services[117] as an Alternative Control Service. The AER also maintained its Alternative Control Service classification for Auxiliary Metering Services (refer to Section 19.1.1).

The AER has approved two types of metering service charges:

- upfront capital charge (for all new and upgraded meters installed from 1 July 2015)
- annual charge comprising of two components:
    - capital – metering asset base (MAB) recovery
    - non-capital – operating expenditure and tax.

Figure 2 illustrates how the two regulated annual charge components apply to different metering customers.



Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 16 – Alternative control services*, April 2015, p21.

Figure 2: Applicable regulated annual charges

[117] Our proposal refers to these services (except the installation of new and replacement meters on customer request) as 'Default Metering Services'.

Annual metering services

The AER generally accepted our building block approach as the basis for establishing annual metering charges. However, it did not accept:

- our opening MAB as at 1 July 2015
- depreciation
- our proposed capital expenditure
- our proposed operating expenditure.

Table 11 summarises the AER's decision on these matters, including its rationale for the changes.

Table 11: AER's decision on the building block approach to annual metering services

Building block component	Ergon Energy's proposal	AER's Preliminary Decision	AER's position
Opening MAB	$61.6 million	$60.7 million	• Corrects an error in the remaining asset lives
Depreciation	Standard asset lives of 3 years for newly installed meters and 5 years for existing meters	Standard asset lives of 15 years	• 15 years is the expected technical lifetime of meters • Small change in the remaining asset lives of metering assets
Capital expenditure	$129.1 million 377,698 meter replacements	$51.3 million 114,919 meter replacements	• Majority of expenditure has been removed due to the introduction of the upfront charge (i.e. Ergon Energy will still be able to recover these costs) • Accepted our proposed material unit costs and non-material unit costs • Rejected forecast volumes. Specifically, the AER: ○ removed our forecast new connections and metering additions and alterations, given the introduction of the upfront charge ○ substituted our forecast meter replacement volumes, which the AER considered to be overstated. The AER noted the sample testing of the Warburton Franki meter family shows that it has not failed the accuracy limits set out in AS1284.13 and Chapter 7 of the NER. It did not consider that age alone to be a good basis on which to replace the meter family.
Operating expenditure	$169.5 million	$118.6 million	• The AER determined a base level of expenditure, by examining our historical operating expenditure and performance against benchmarking. The AER observed our operating expenditure per customer is less than Essential Energy and concluded that we are relatively efficient. The AER accepted a historical operating expenditure of $32 per customer per year as the base • The AER did not accept our step change relating to preventive meter maintenance. AEMO indicated this is not a new obligation. Therefore, the AER concluded that it cannot be a step change • The AER did not forecast metering operating expenditure per customer to increase in the period.

Building block component	Ergon Energy's proposal	AER's Preliminary Decision	AER's position
			Consequently, it applied zero real price and productivity growth

The AER rejected our proposed price caps for annual metering charges. The reason for this is twofold:

- The AER did not accept the components of our building block proposal, and therefore the metering ARRs which were used to establish our annual metering charges.
- The AER did not accept our proposal to include the capital costs of new/upgraded connections in the annual metering charges.

Table 12 sets out the annual metering charges determined by the AER.

Table 12: AER's preliminary determination on Ergon Energy's annual metering charges, 2015-20

Tariff class $/unit (nominal)	Costs	2015-16	2016-17	2017-18	2018-19	2019-20
Primary Service	Non-capital	24.44	25.75	27.14	28.60	30.13
	Capital	6.49	6.84	7.21	7.59	8.00
Controlled load	Non-capital	8.99	9.47	9.98	10.51	11.08
	Capital	2.39	2.51	2.65	2.79	2.94
Solar	Non-capital	6.08	6.40	6.75	7.11	7.49
	Capital	1.61	1.70	1.79	1.89	1.99

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 16 – Alternative control services*, April 2015, p64.

Upfront charges

The AER did not accept our proposal to include the capital costs of new/upgraded connections in the annual metering charge. Rather, the AER determined that these costs should be recovered from customers as an upfront charge. The AER indicated that this would ensure the costs are attributed to the customer who initiates the metering installation, avoids the need to forecast capital expenditure for new and upgraded metering installations that may not eventuate, and promotes competition.

Calculation of upfront charges

To calculate the upfront charges, the AER used the proposed costs for the installation of an additional meter (a quoted service) and added the forecast cost of materials based on the 'top end' of the observed market range for particular categories determined by its consultant, Marsden Jacobs. The AER distinguished between three types of meters: single phase, dual element and three phase Type 6 meters.

Table 13 sets out the upfront charges determined by the AER for new/upgraded connections.

Table 13: AER's preliminary determination on Ergon Energy's upfront new/upgraded connection charges, 2015-16

Meter $/unit (nominal)	Materials	Labour	Capital allowance	Total
Single phase	100	250.18	43.45	393.63
Dual element	150	250.18	43.45	443.63
Three phase	189.27	250.18	43.45	482.90

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 16 – Alternative control services*, April 2015, p49.

The AER did not accept our proposal to apply separate charges, based on the feeder type. Instead, it applied a flat labour rate, stating this is consistent with our proposal for quoted services. The AER also noted it was consistent with Essential Energy's proposal.

The upfront charge will be updated each year for labour price changes. The AER has also applied a weighted X-factor, with a 60 per cent weighting to the labour price changes.

Exit fee

Our October Regulatory Proposal included a Customer Transfer Fee which recovers the administration and metering asset costs associated with a customer transferring to an alternative metering provider. This was consistent with the classification of services set out in the AER's Framework and Approach Paper.

In its Preliminary Determination, the AER decided to recover the residual capital costs through the capital component of the regulated annual metering charge. Further, the AER did not accept our proposal to recover administrative costs. It considered that Ergon Energy will not incur incremental costs, as we will not need to perform any additional tasks or functions when a customer switches. Rather, the acquirer of the new meter – the retailer – would. The AER also did not believe the proposed transfer fee is reasonable, given the metering operating expenditure per customer is $32. As such, a meter exit fee will not apply.

Control mechanism

Consistent with the Framework and Approach Paper and our October Regulatory Proposal, the AER has applied caps on the prices of individual services. For the first year, the AER has determined a schedule of prices. For the following years, the previous year's prices are adjusted by CPI and an X factor.

The control mechanism is as follows:

$$p_i^t = p_i^{t-1}(1 + \Delta CPI_t)\left(1 - X_i^t\right) + A_i^t$$

Where:

p_i^{t-1} is the cap on the price of service i in year t-1

p_i^t is the cap on the price of service i in year t

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t–1. For example, for the

2015-16 year, t-2 is December 2013 and t-1 is December 2014 and in the 2016-17 year, t-2 is December 2014 and t-1 is December 2015 and so on.

A_i^t is zero

X_i^t is:

- for the annual metering charges, the factors set out in Table 16.6 of Attachment 16 of the Preliminary Determination
- for the upfront charges, the factors set out in Table 16.7 of Attachment 16 of the Preliminary Determination.

Compliance with the control mechanism must be demonstrated in the annual Pricing Proposal.

19.2.2. Stakeholder feedback

Canegrowers Isis Ltd did not support the classification of Default Metering Services as an Alternative Control Service, citing that these costs should not become an individual cost to customers.[118] On the other hand, Vector supported the unbundling of these services.[119]

QCOSS also recommended that the AER review the methodology and assumptions underlying the calculation of our annual metering service charges. In particular, QCOSS queried:

- the difference between the opening MAB value as at 1 July 2015 and the amount deducted from the Standard Control Services RAB on 30 June 2015
- the forecasts of new and replacement meter installations
- our accelerated depreciation approach. QCOSS considered an assumed remaining life of 15 years is more reasonable
- our proposed metering operating expenditure. QCOSS cited that Ergon Energy reads meters less frequently than Energex (which proposed a lower operating expenditure) and requires some customers to perform self-reads
- whether the savings likely to arise from the uptake of smart meters have been taken into account in developing the capital and operating expenditure forecasts.[120]

Finally, a number of stakeholders did not support the introduction of a meter exit fee, or considered the exit fees proposed by Ergon Energy were too high.[121] Stakeholders stated the exit fees would affect competition, acting as a disincentive to the uptake of smart meters.[122] COTA Queensland suggested that the residual capital costs of meters should be written off or included in the forecast of the annual metering service charges allocated to all consumers.[123] Vector considered these costs, and administration costs associated with the meter transfer, should be classified as a Standard Control Service.[124]

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[118] Canegrowers Isis Ltd, Op. cit, p3.
[119] Vector (2015), *Submission on the AER's Issues Papers on Queensland and SA Electricity Distributors' regulatory Proposal for 2015-16 to 2019-20,* 30 January 2015, p3.
[120] QCOSS, Op. cit, pp88-89.
[121] See, for example, Origin Energy, Op.cit, p2; COTA Queensland, Op. cit, p3 and Vector, Op. cit, p2.
[122] See, for example, Energy Retailers Association of Australia, *RE: Qld electricity distribution regulatory proposals 2015-16 to 2019-20 Issues paper,* 29 January 2014, p2 and Australian PV Institute, Op. cit, p7.
[123] COTA Queensland, Op. cit, p3.
[124] Vector, Op. cit, p4.

19.2.3. Other influencing factors

On 22 May 2015, Ergon Energy wrote to the AER expressing our concerns relating to the imposition of upfront capital charge. We highlighted that:

- The AER has effectively dismissed our customer and stakeholder engagement and does not appear to have undertaken any consultation to support the imposition of an upfront capital charge.
- The upfront capital charge will impede customers choosing cost reflective tariff options as these require a meter installation or upgrade. The installation of solar PV systems and adoption of controlled load tariffs also require a meter installation or upgrade.
- Customers will respond negatively to the imposition of an upfront capital charge, which will increase complaints to Ergon Energy and enquiries to the Queensland Energy and Water Ombudsman.
- Ergon Energy has a very limited timeframe to communicate the change to our customers, retailers and electrical contractors before the charges take effect from 1 July 2015.

The AER reaffirmed its position that customers should pay upfront for new and replacement meters. However, the AER may consider alternative pricing arrangements that would give effect to customers being charged for the meter upfront.

Our response to the AER's Preliminary Determination has been driven by a number of additional factors:

- We have updated our base year operating expenditure to 2013-14, consistent with Standard Control Services.
- We have updated our forecast inflation rates and escalators to reflect new data provided by Jacobs.
- We have adjusted our forecasts to reflect the AER's decision on new and replacement meters.
- We have updated for the latest rate of return consistent with Standard Control Services.

19.2.4. Our response

Ergon Energy generally does not support the AER's Preliminary Determination. We are particularly concerned by the AER's decision to:

- implement upfront capital charges
- remove the exit fee and instead introduce annual capital charges.

We also do not agree with changes made by the AER in relation to the calculation of the ARRs for annual metering services, as we have differing positions on the underlying building blocks.

Ergon Energy also notes that we have used the January 2015 version of the PTRM for Default Metering Services, which allows for a time-varying return on debt. Therefore, we question whether the AER intends to annually adjust for the return on debt as per the approach adopted for Standard Control Services.

A summary of our concerns and revisions made in our Regulatory Proposal is below. Our detailed response is contained in *Metering – Response*.

Annual metering services

Ergon Energy has applied the AER's proposed structure in our revised Regulatory Proposal.

We do not agree with many of the changes made by the AER to the underlying building blocks, including:

- aged asset replacement capital expenditure for Ferranti (Type M2) and Warburton Franki meters. In relation to Ferranti meters, given the small sample size, it is more efficient to replace the meters than undertaken on-site testing. In relation to the Warburton Franki meters, we have assessed compliance under the Australian Standard and this, together with preliminary meter testing results, indicates that this meter family is non-compliant. Final in-situ testing results will be available by September 2015. Ergon Energy expects the AER to include capital expenditure for these meters in its Substitute Determination given they are non-compliant.
- accelerated depreciation. Ergon Energy believes an accelerated depreciation approach would best promote efficient cost recovery and deliver benefits to customers. This approach is more consistent with the efficient cost recovery and pricing principles set out in the NER than the AER's proposed approach.
- operating expenditure. Ergon Energy has identified an error in the historical metering costs in the Economic Benchmarking RIN. The historical metering costs did not include of the metering operating expenditure that relates to future state Alternative Control Services metering costs. This means operating expenditure relating to meter queries, maintain meter equipment and maintain broken seals has been excluded from our metering base year operating expenditure. We also consider there should be two adjustments to the base year operating expenditure (see step changes below)
- WACC and gamma. We have updated our metering proposal to reflect the values we have proposed for Standard Control Services.

We have also identified an error in the capital expenditure forecasts. This error arose from an administrative error in transposing the table and had the effect of under-estimating the direct costs metering capital expenditure component and over-estimating the overheads component.

Finally, Ergon Energy proposes that the AER account for differences between the 2015-16 prices approved in the Preliminary Determination and those approved in the Substitute Determination via a 'true-up' mechanism which would adjust the prices in the remaining years of the regulatory control period 2015-20.

Upfront charges

Ergon Energy does not support the AER's decision to levy an upfront charge on new customers to recover the full capital cost of new or replacement meters. Our concerns relating to the imposition of these charges are highlighted in Section 19.2.3.

We also do not agree with the approach taken by the AER to calculate the charges. This is because:

- The AER has applied an inconsistent approach between Ergon Energy and Energex. In particular:
  - The AER applied a separate upfront capital charge for the provision and installation of LVCT meters for Energex, but did not apply one to us. Ergon Energy had approximately 1,000 LVCT meter installations annually in the regulatory control period 2010-15 and we expect this to continue in the regulatory control period 2015-20.

    - The AER applied a meter cost at the bottom end of the consultant's range for the three phase meters for Ergon Energy, but used the top end of the range for Energex. Our actual meter costs are closer to the top end of the range.
- The AER has not allowed differentiation in charges by feeder type. There are significant differences between the labour costs that Ergon Energy incurs in providing services to our customers across our vast service area. These differences have been recognised in the fee based services approved by the AER in the regulatory control period 2015-20 and the previous period, and the approach we take for quoted services (which reflect the actual cost of the job being undertaken). The AER's approach is inconsistent with promoting cost-reflective pricing and results in significant cross-subsidies between customers.

If the AER chooses to retain its approach to charging separate fees for new or replacement meters, Ergon Energy proposes to recover these costs as either a fee based or quoted service. Specifically, we propose:

- eight new fee based services, which are differentiated by the type of meter (i.e. single phase, dual element, three phase and CT) and the type of feeder the customer is connected to (i.e. either urban/short rural or long rural)
- one new quoted service, which would apply to any installation and provision of a Type 5 or 6 meter after hours.

Further details on these charges, and our rationale for proposing them, is contained in *Metering – Response.*

Exit fee

Ergon Energy retains the view that we presented in our October Regulatory Proposal and in subsequent submissions to the AER that an exit fee is the most equitable mechanism for recovering residual metering costs that arise when a meter is replaced by an upgraded meter. However, we have updated our Regulatory Proposal to reflect the AER's decision to apply capital charges.

This is because Ergon Energy made a number of system and process changes to enable the introduction of these capital charges from 1 July 2015. We have also communicated these changes to relevant stakeholders. Unwinding these changes in 2016-17 would create unnecessary costs.

Despite this, as noted above, we have maintained our position in relation to accelerated depreciation. We consider this approach is better as it allows us to recover the residual capital metering costs from the customer who benefits from the meter and in a reasonable timeframe. That is, the affected customer can relate its payment to the meter it asked to have replaced.

Control mechanism

Ergon Energy accepts the AER's decision to apply a price cap form of control.

We note, in light of the changes we are proposing to upfront capital charges, the metering control mechanism formula will not apply to the installation and provision of meters after 1 July 2015. This means Table 16.7 of the Preliminary Determination will no longer be required.

Step changes

Ergon Energy accepts the AER's decision to reject our step change relating to in-situ testing. However, in its place a base year adjustment is required. Ergon Energy agrees with the AER that we do not have any new regulatory obligation for meter testing. It was never Ergon Energy's intention to characterise our step change in this manner. Rather, Ergon Energy sought to identify existing regulatory requirements that are not provided for in our 2012-13 operating expenditure base year.

During the previous two regulatory control periods, Ergon Energy did not undertake in-situ testing every year. We performed this testing between 2007 and 2010 and then again in 2014-15. Therefore, our operating expenditure forecasts (both in the October Regulatory Proposal and the revised Regulatory Proposal, which is based on a 2013-14 base year) do not include any allowance for recurrent in-situ testing. A base year adjustment is therefore required.

We are also propose to include, as part of the base year adjustment, costs relating to our requirement to test voltage and current transformers at shared Powerlink and Ergon Energy wholesale metering points. This testing needs to be performed every 10 years in accordance with Chapter 7 of the NER and has not been included in our base year operating expenditure.

19.3. Public Lighting

19.3.1. Preliminary Determination

Annual public lighting services

The AER generally accepted our building block approach as the basis for establishing annual public lighting charges, as well as our proposed changes to the types of charges. However, it did not approve our public lighting charges because it determined to apply:

- a nominal post-tax WACC of 5.85 per cent
- a value of imputation credits of 0.40.

This resulted in a total revenue reduction of $16.9 million over the five year period.

Table 14 sets out the annual public lighting charges determined by the AER.

Table 14: AER's preliminary determination on Ergon Energy's annual public lighting charges, 2015-20

Public Lighting Services $/light (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
EO&O - Major	1.0252	1.0621	1.1062	1.1446	1.774
EO&O - Minor	0.6108	0.6320	0.6581	0.6804	0.6990
G&EO - Major	0.4140	0.4217	0.4376	0.4479	0.4528
G&EO - Minor	0.2712	0.2762	0.2867	0.2933	0.2964

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 16 – Alternative control services*, April 2015, p58.

LED transition program and exit fees

The AER accepted our proposed light emitting diode (LED) transition program and exit fees. The exit fees are payable when a public light is scrapped before the end of its useful operational life (outside of the LED program).

Control mechanism

Consistent with the Framework and Approach Paper and our October Regulatory Proposal, the AER has applied caps on the prices of individual services. For the first year, the AER has determined a schedule of prices. For the following years, the previous year's prices are adjusted by CPI and an X factor.

The control mechanism is as follows:

$$p_i^t = p_i^{t-1}(1 + \Delta CPI_t)\left(1 - X_i^t\right) + A_i^t$$

Where:

p_i^{t-1} is the cap on the price of service i in year t-1

p_i^t is the cap on the price of service i in year t

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t-1. For example, for the 2015-16 year, t-2 is December 2013 and t-1 is December 2014 and in the 2016-17 year, t-2 is December 2014 and t-1 is December 2015 and so on.

X_i^t is the value of X for the year t in the regulatory control period. There are no X-factors for public lighting

A_i^t is zero.

Compliance with the control mechanism must be demonstrated in the annual Pricing Proposal.

19.3.2. Stakeholder feedback

LGAQ appreciated our work to improve the accuracy of public lighting inventories and the future development of LightMap, as well as progress made to date on the Service Level Agreement. However, it raised concerns with the end of life treatment of contributed public lights; given distributors do not make an allowance for the replacement of these assets in their forecasts and the costs are borne by the public lighting customer.[125]

The Far North Queensland Regional Organisation of Councils in principle supported the LED transition program and the sunk costs of assets being spread across all public lighting customers. However, it queried whether:

- LEDs have been factored into the depreciation allowance
- maintenance costs have been lowered to take into account the introduction of LEDs.

Further, it did not support customers having to pay an exit fee outside of the LED program. With respect to exit fees, it:

- suggested the exit fees should be dependent on the age of the asset
- queried whether an exit fee should be paid for gifted public lights.[126]

19.3.3. Other influencing factors

Ergon Energy has become aware of an incorrect statement in our *Public Lighting Forecast Expenditure Summary document*. Specifically, the document references "the reversal of the tax

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[125] LGAQ, Op. cit, p3.
[126] Far North Queensland Regional Organisation of Councils, Op. cit, pp5-6.

shelter related to tax deprecation rates on assets" on page 26. This explanation does not clearly articulate the impacts of capital contributions on the tax income calculation. We have therefore amended this statement in our revised Regulatory Proposal.

Our response to the AER's Preliminary Determination has been driven by a number of additional factors:

- We have updated our base year operating expenditure to 2013-14, consistent with Standard Control Services.
- We have updated our forecast inflation rates and escalators to reflect new data provided by Jacobs.
- We have updated for the latest rate of return consistent with Standard Control Services.
- We have updated customer numbers to reflect our latest forecasts.

19.3.4. Our response

Ergon Energy generally supports the AER's Preliminary Determination on public lighting. We have amended our proposal to reflect:

- our positions on the rate of return and CPI, as per our Standard Control Services response
- updated customer numbers.

We also propose that the AER account for differences between the 2015-16 prices approved in the Preliminary Determination and those approved in the Substitute Determination via a 'true-up' mechanism which would adjust the prices in the remaining years of the regulatory control period.

It is important to note that we have not adopted the modified WARL approach (as used for calculating the remaining life of assets in the RAB for Standard Control Services) for calculating remaining asset lives for public lighting assets. This means we have not created public lighting asset classes for assets installed pre 2009-10 and post 2009-10 as we did for the asset classes in the RAB for Standard Control Services.

We adopted the AER's WARL approach for calculating the remaining lives for public lighting assets without modification and have not modified the existing public lighting asset classes in any way.

Ergon Energy also notes that we have used the January 2015 version of the PTRM for Public Lighting Services, which allows for a time-varying return on debt. Therefore, we question whether the AER intends to annually adjust for the return on debt as per the approach adopted for Standard Control Services.

Finally, we have identified an input error in the PTRM published as part of the Preliminary Determination. The AER has applied an inflation rate of 2.38 per cent instead of 2.55 per cent.

Our detailed response is contained in *Public Lighting Services – Response*.

20. Negotiated distribution services framework and criteria

This section summarises our response to the AER's decision on the negotiated distribution services framework and criteria. The framework and criteria govern the manner in which negotiations between Ergon Energy and a person wishing to receive a negotiated service should occur, and the terms and conditions of access for the provision of the service.

There are no negotiated services applying in the regulatory control period 2015-20.

20.1. Preliminary Determination

The AER accepted our proposed negotiated distribution services framework and criteria.

20.2. Stakeholder feedback and other influencing factors

There has been no stakeholder feedback received on our proposed negotiated distribution services framework and criteria. Further, there are no other factors influencing the negotiated distribution services framework and criteria.

20.3. Our response

Ergon Energy agrees with the AER's decision to accept our proposed negotiated distribution services framework and criteria. We have not made any revisions to our October Regulatory Proposal.

21. Connection Policy

This section summarises our response to the AER's decision on our proposed Connection Policy. The Connection Policy covers the charges that retail customers or real estate developers are required to pay for connection services provided under Chapter 5A of the NER and the basis for determining those charges.

21.1. Preliminary Determination

The AER did not approve our connection policy because:

- the upstream shared network asset augmentation charge rate is not consistent with the AER's Connection Charge Guidelines
- certain terms and conditions needed further clarification.

21.1.1. Marginal cost of shared network augmentation

The AER accepted our proposed marginal cost of $1,486.49 per kVA for 2015-16.[127] In reaching this decision, the AER noted that this rate is less than:

- the Productivity Commissions findings on the long run marginal cost of network augmentation
- our historical average shared network costs, as detailed in our 2013-14 Economic Benchmarking RIN.

21.1.2. Shared network augmentation charge rate

The AER did not accept our proposal to apply the full marginal cost as the shared network augmentation charge. The AER considers this is inconsistent with its Connection Charge Guideline as it does not take into account the connection lives of new connections.

To calculate the charge rate, the AER has applied the method set out in its *Explanatory Statement for the Proposal Connection Charge Guidelines: under chapter 5A of the National Electricity Rules for accessing the electricity distribution network.* An adjustment factor of 0.574 and 0.818 should be applied to the proposed full charge out rate for business and residential customers, respectively.

21.1.3. Terms and conditions

The AER considers the majority of our proposed terms and conditions meet the minimum requirements of the NER. However, it has made some minor changes to our proposed Connection Policy to assist readers to understand the charging framework.

21.2. Stakeholder feedback

There has been no stakeholder feedback received on our proposed Connection Policy.

21.3. Other influencing factors

Ergon Energy has updated forecast inflation rates to reflect new data provided by Jacobs. This has impacted the augmentation unit rates proposed for each year of the regulatory control period

[127] To be indexed by CPI for each regulatory year.

2015-20. The updated forecast inflation rates also impact the thresholds for refunds and staged payments.

21.4. Our response

Ergon Energy accepts the clarification changes made to our proposed Connection Policy. We have revised our supporting document, *09.01.01 – (Revised) Ergon Energy Connection Policy*, to include these amendments given we have had to change systems and processes to implement the policy from 1 July 2015 and amending our approach would result in equitable treatment for customers across the regulatory control period. Ergon Energy notes that as a result there will be increased costs for all customers as larger exporting PVs drive upgrade costs. That is, under our original policy these customers would have contributed to the costs rather than them being funded by all customers.

We have updated the marginal cost for 2015-16 to reflect forecast inflation resulting in a rate of $1,472.40 per kVA, as allowed for under the approved Connection Policy. However, we do not agree with the adjustment factor the AER has applied to calculate the augmentation unit rates. Despite this, we have updated our Regulatory Proposal and supporting document *09.02.01 – (Revised) Unit Rates for Capital Contributions*. Ergon Energy has also amended the proposed augmentation unit rates to reflect updated inflation forecasts provided by Jacobs.

Ergon Energy has also made a minor amendment to the policy to include reference to the upfront meter costs following the AER’s preliminary decision on Default Metering Services.

22. Other revisions

In addition to the amendments outlined above, Ergon Energy has made a number of other revisions to our October Regulatory Proposal. These changes are described in Table 15.

Table 15: Other revisions to October Regulatory Proposal

Topic	Description of change	Revised documents
Overview document	• Updated to reflect our revised Regulatory Proposal, including our revised customer commitments	• *0A.00.01 – (Revised) An Overview, Our Regulatory Proposal 2015-20*
Best Possible Price	• Minor revisions made to reflect changes in circumstances since October, included our updated customer commitment.	• *04.01.02 – (Revised) Ergon Energy's Journey to the Best Possible Price*
Legislative obligations	• Replaced references to the Electricity Industry Code. From 1 July 2015, the Electricity Distribution Network Code will replace the Electricity Industry Code • Updated to reflect requirements of the National Energy Customer Framework that was introduced from 1 July 2015 • Updated to reflect recent announcements relating to Queensland Government electricity sector reforms • Ergon Energy notes that AS4777 is currently under review. This review includes the definition of a micro embedded generator. If there are changes arising from this review that impact our classification of services or connection policy we will advise the AER as soon as possible.	• *01.01.01 – (Revised) Legislative and Regulatory Obligations and Policy Requirements* • *02.01.01 – (Revised) Classification Proposal*
Key assumptions	• The base year has been updated to 2013-14. This reflects the most recent audited financial statements available for the purpose of forecasting	• Regulatory Proposal: ○ Table 38: Operating expenditure assumptions, 2015-20 ○ Table 48: Capital expenditure assumptions, 2015-20 Note – we are not required under the NER to recertify our key assumptions. Therefore, our supporting document, *06.01.06 – Certification of reasonableness – expenditure forecast assumptions,* has not been updated. • *06.01.05 – Meeting the Rules Requirements*
Confidentiality template	• Updated to reflect our new suite of documents and revisions to existing documents	• *11.01.01 – (Revised) Confidentiality template*

Appendix A. Supporting evidence regarding capital governance (confidential)

Slide 1

[redacted]

Source: Ergon Energy (2014), Board and Regulatory Committee sign off presentation slide pack, July 2014.

Glossary

ABS	Australian Bureau of Statistics
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ALARP	As Low As Reasonably Practical
ARR	Annual Revenue Requirement
ATO	Australian Tax Office
Capex	Capital expenditure
CCP	Consumer Challenge Panel
CEO	Chief Executive Officer
CESS	Capital Expenditure Sharing Scheme
CPI	Consumer Price Index
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DUOS	Distribution Use of System
EBSS	Efficiency Benefit Sharing Scheme
FiT	Feed-in tariff
Gamma	Value of imputation credits
GSL	Guaranteed Service Level
LED	Light emitting diode
LGAQ	Local Government Association of Queensland
MAB	Metering asset base
MSS	Minimum Service Standards
MTA	Minimalist Transitioning Approach
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	Net Present Value
NSP	Network service provider
NSW	New South Wales

Opex	Operating expenditure
PTRM	Post Tax Revenue Model
PV	Photovoltaic
QCOSS	Queensland Council of Social Service
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
RIN	Regulatory Information Notice
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SFAIRP	So Far As Is Reasonably Practical
SL CAPM	Sharpe-Lintner Capital Asset Pricing Model
STPIS	Service Target Performance Incentive Scheme
TAB	Tax asset base
TAR	Total annual revenue
TUOS	Transmission Use of System
VCR	Value of Customer Reliability
WACC	Weighted Average Cost of Capital
WARL	Weighted average remaining life