Submission to the AER on its Preliminary Determination

Metering

Summary

This document sets out Ergon Energy's response to the Australian Energy Regulator (AER) on Alternative Control Services – Default Metering Services.

Ergon Energy disagrees with many aspects of the AER's Preliminary Determination. Ergon Energy is concerned with the AER's approach and structure of the Default Metering charges. We continue to consider that an exit fee is the most equitable mechanism for recovering residual metering costs. However, if the AER retains its proposed fee structure from its Preliminary Determination, then it should make the changes that we have proposed in this document.

Ergon Energy has updated our October Regulatory Proposal to reflect:

- **The 2013-14 base year for operating expenditure (Opex)**
- **Updated inputs including overhead rates, inflation, escalators and the rate of return parameters**
- **Upfront charges for new and replacement meters**

Capital and non-capital charges for recovery of the costs associated with the Default Metering Service

Outcomes

The changes proposed in this document are necessary to ensure that Ergon Energy can deliver efficient metering services consistent with our legal obligations and customer needs. The outcomes that will flow from the AER's acceptance of Ergon Energy's proposals in this document are:

- **Upfront capital charges for new and replacement meters which now include overheads and on-cost in addition to the hardware cost of the meter**
- **Up-front capital charges that vary by feeder type for each meter category which limits cross-subsidisation for customers**
- **The replacement of non-compliant meters so that Ergon Energy can maintain regulatory compliance**
- **An Opex allowance sufficient for Ergon Energy to deliver its required metering services to customers**
- **Improved ability to recover residual metering costs from customers that initiated the meter replacement.**

Contents

1. Introduction

On 30 April 2015, the Australian Energy Regulator (AER) released its Preliminary Determination on Ergon Energy's Regulatory Proposal for the regulatory control period commencing on 1 July 2015 and ending on 30 June 2020.

This document details our response to the AER's Preliminary Determination on Default Metering Services. We have made revisions to our Regulatory Proposal and its supporting documents to reflect these positions, where necessary. In addition, we have revised our proposal to reflect updated inputs (e.g. overheads, escalators and forecast inflation).

Ergon Energy has structured this document in the following manner:

- Chapter 2 summarises the AER's Preliminary Determination in relation to Default Metering Services.
- Chapter 3 outlines issues raised by stakeholders since the lodgement of our initial Regulatory Proposal, both through our own consultation process and the AER's.
- Chapter 4 provides our response to the positions adopted by the AER, and the areas of our October Regulatory Proposal which have been revised as a result.
- Chapter 5 sets out areas of our October Regulatory Proposal which have been revised due to new or updated information, or changes in methodology.

2. AER's Preliminary Determination

Attachment 16 of the AER's Preliminary Determination details its positions on Alternative Control Services (ACS) including Default Metering Services. The following sections summarise the AER's positions and rationale on Default Metering Services.

2.1. Classification of services

In line with its Framework and Approach Paper, the AER classified Type 5 and 6 metering installation, provision, maintenance, reading and data reading services as an ACS. The AER also maintained its ACS classification for Auxiliary Metering Services.

2.2. Building block approach

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

- our opening Metering Asset Base (MAB) as at 1 July 2015
- our proposed depreciation
- our proposed capital expenditure
- our proposed operating expenditure.

Table 1 summarises the AER's decision on these matters, including its rationale for the changes.

Table 1: 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 113,919 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: o removed our forecast new connections and metering additions and alterations, given the introduction of the upfront charge o 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

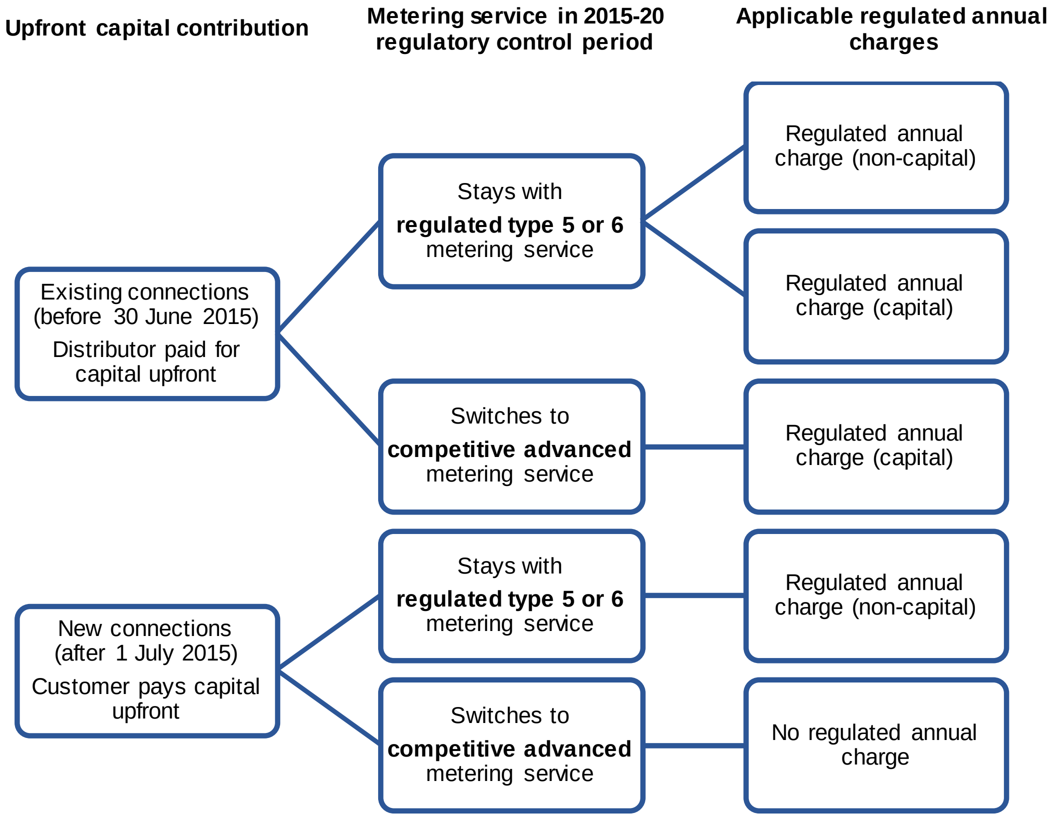
Building block component	Ergon Energy's proposal	AER's Preliminary Decision	AER's position
			the National Electricity Rules (NER). It did not consider that age alone to be a good basis on which to replace the meter family.
Operating expenditure	$169.5 million	$118.6 million	• The AER determined a base 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. The Australian Energy Market Operator (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. Consequently, it applied zero real price and productivity growth

2.3. Metering charges

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 – MAB recovery
  - non-capital – operating expenditure and tax.

Figure 1 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 1: Applicable regulated annual charges

2.3.1. Annual metering services

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 Annual Revenue Requirement 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 2 sets out the annual metering charges determined by the AER.

Table 2: 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.

2.3.2. Upfront charges

The AER did not accept our proposal to include capital costs of new/upgraded connections in the annual metering charge. Rather, the AER determined that these costs should be fully 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 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.[1] Single Phase and dual elements were based on the 'top end' of the observed market range while three phase meters were based on the 'low end' of the range.

Table 3 sets out the upfront charges determined by the AER for new/upgraded connections.

Table 3: AER's preliminary determination on Ergon Energy's upfront new/upgraded connection charges, 2015-16 ($/unit nominal)

Meter	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 allow separate charges to be 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.

Separate charge for Low Voltage Current Transformer (LVCT) meters

The AER has not made any specific provision in its Preliminary Determination for Ergon Energy levying a separate up-front capital charge for the provision and installation of LVCT meters and associated charges i.e. Current Transformers (CTs), test terminals, fuse kit site commissioning.

[1] In defining the meter types, "single phase" refers to a single phase single element meter whereas "dual element" refers to a single phase two element meter. This terminology has been applied throughout Ergon Energy's documentation for this revised Regulatory Proposal.

2.3.3. 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 was assessed to be $32. As such, the AER determined that a meter exit fee will not apply.

2.4. 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 the Consumer Price Index (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.

2.5. Rate of return parameters

The AER's Preliminary Determination for the nominal post-tax weighted average cost of capital (WACC) was 5.85 per cent instead of the Ergon Energy's proposed 8.02 per cent. The preliminary decision for imputation credit (gamma) was 40 per cent instead of Ergon Energy's proposed 25 per cent. Ergon Energy's proposal for WACC and gamma for ACS was based on the same assumptions as the Standard Control Service (SCS) proposal.

3. Stakeholder comments

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.[2] On the other hand, Vector supported the unbundling of these services.[3]

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.[4]

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.[5] Stakeholders stated the exit fees would affect competition, acting as a disincentive to the uptake of smart meters.[6] 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.[7] Vector considered these costs, and administration costs associated with the meter transfer, should be classified as a Standard Control Service.[8]

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[2] Canegrowers Isis Ltd (2015), *Re: Qld electricity distribution regulatory proposals 2015-16 to 2019-20,* 30 January 2015, p3.
[3] 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.
[4] QCOSS (2015), *Understanding the long term interests of electricity customers: Submission to the AER's Queensland electricity distribution determination 2015-2020,* 30 January 2015, pp88-89.
[5] See, for example, Origin Energy (2015), *RE: Submission to Queensland Electricity Distributors' Regulatory Proposals*, 30 January 2015, p2; COTA Queensland, (2015), *Ergon Energy Regulatory Proposal 2015-20,* 30 January 2015, p3 and Vector, Op. cit, p2.
[6] 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 (2014), *APVI Submission to the AER on the Issues Paper on Ergon's and Energex's Network's Regulatory Proposals December 2014*, p7.
[7] Op. cit, p3.
[8] Vector, Op. cit, p4.

4. Our Response

The following sections detail our response to the AER's Preliminary Determination.

4.1. Classification of services

The AER's decision on the classification of services is consistent with the approach in our October Regulatory Proposal and the Framework and Approach Paper. As such, we accept the AER's decision on this matter.

4.2. Building blocks

Ergon Energy does not agree with the approach taken by the AER to amend our building blocks. The following sections set out our response to the AER's decision.

4.2.1. Opening MAB

Ergon Energy does not accept the AER's Preliminary Determination on the remaining asset lives and as such has not updated the opening MAB value in our Regulatory Proposal.

4.2.2. Aged asset replacement capital expenditure

Ergon Energy included six meter types in its capital expenditure (Capex) replacement program for its metering services. The AER's Preliminary Determination accepted the replacement of four meter types and rejected the replacement of the other two meter types. This resulted in the AER substituting Ergon Energy's proposed meter replacement volume of 108,450 for the forthcoming regulatory control period with a volume of 64,669. As a result, the AER excluded $14.4 million of direct costs (excluding overheads) from Ergon Energy's proposed end of life Capex replacement program for its metering services.

The two meter types that the AER rejected are Ergon Energy's:

- Warburton Franki (Type WF2) meters – Ergon Energy has 42,781 units in service. These meters are manufactured prior to 1963, and are more than 50 years old and showing signs of failure; and
- Ferranti (Type TM2c) meters – these meters were purchased in 1965. Ergon Energy has 1,000 units in service.

The AER rejected replacing these meter types because they have not failed the accuracy limits under AS1284.13. The AER did not accept Ergon Energy's proposal to replace meters based on their age.

The framework for "end of life" meter replacement that Ergon Energy used in its October Regulatory Proposal was based on the AER's Repex document, which indicated that equipment with an age twice its operating life and showing signs of failure could be considered for replacement.

The Ferranti Type TM2c meter make is a small meter family. For small family populations like this, it is considered that replacement of the meters is more practical than ongoing in-situ testing of samples particularly given the age and expected increase in failure rates of meters approaching 50 years old. The quantity of meters that need to be tested for compliance testing is relatively large (i.e. approaching 10%). For a meter population of 1,000 a completed sample of 80 is necessary, generally requiring visits to over 100 sites to achieve the test sample due to access and other related issues.

Ergon Energy's rationale for proposing to replace the Ferranti Type TM2c meter make is that it would eliminate the need for future in-situ compliance testing.

Therefore Ergon Energy continues to consider that the replacement of this type of meter will be more cost effective and thus efficient for customers than having to pay for on-going periodic testing of these meters. Given the cost to replace a meter is not significantly greater than the cost to perform the onsite testing, Ergon Energy would prefer to be able to replace the Ferranti meters to avoid ongoing testing costs, reduce failure in service impacts and incorporate into approved replacement programs to avoid additional project establishment and management costs in the future. As a result we have not updated our revised Regulatory Proposal to reflect the AER's Preliminary Determination with respect to replacement of Ferranti (Type TM2c) meters.

In relation to the Warburton Franki meters, as a result of further testing data and a reassessment of the criteria under Australian Standard 1284.13, Ergon Energy considers that this meter family is "non-compliant".

In both our October Regulatory Proposal and additional information provided to AER in response to its question AER Ergon 043(2)a in relation to these meters, Ergon Energy misinterpreted the definition of a "non-compliant" meter under the Standard. In these previous documents, we interpreted the Standard as requiring that the meter must fail on both Light Load (LL) and Full Load (FL) testing under Criteria 3. Upon closer examination of the wording of AS 1284.13, clause 8.7.3 we now understand that the Standard indicates that a meter family which fails **either the LL or the FL** testing under criteria 3 is "non-compliant". This clause relates to the "accuracy by attributes" and provides that:

> *If the number of meters that exceeds the accuracy limits of Criteria 3 of Table 4 or Table 5 is greater than or equal to the fail level for light* ***or*** *Full Load of Table 1, then the population fails the test.*

On this corrected interpretation of the Standard, Ergon Energy considers that Warburton Franki (Type WF2) meters are non-compliant and therefore must be replaced. This is supported by current testing of these meters. Our preliminary testing of these meters presented in the table in response to question AER Ergon 043(2)b (and replicated below in table 4) supports the view that our Warburton Franki meters are "non-compliant" under AS 1284.13 clause 8.7.3.

Table 4: Preliminary meter testing results

Criteria 1 - 2%				Criteria 2 - 2.5%				Criteria 3 - 3%			
FL		LL		FL		LL		FL		LL	
Pass	Fail	Pass	Fail	Pass	Fail	Pass	Fail	Pass	Fail	Pass	Fail
21	22	21	22	21	22	21	22	21	22	21	22
77		101		26		54		18		39	
Fail		Fail		Fail		Fail		Pass		Fail	

Approximately, 80 per cent of a second round of testing of this meter type has now been completed. Ergon Energy will complete its in-situ testing of Warburton Franki meters by July 2015, with the results analysed and available by September 2015. We expect these results to confirm our view that these meters are non-compliant.

Given that these Warburton Franki (Type WF2) meters are non-compliant, Ergon Energy considers that the associated replacement Capex that was included in our October Regulatory Proposal should be reinstated and reflected in its meter replacement program. This would be consistent with AER's reasoning for agreeing to the replacement of other meter families (i.e. EMMCO type BAZ meters) in its Preliminary Determination. As a result, Ergon Energy has not updated our revised Regulatory Proposal to reflect the AER's Preliminary Determination in relation to Warburton Franki meters.

If the AER does not accept the need to fund the replacement of the 42,761 Warburton Franki meters during the regulatory control period, Ergon Energy will be in a position of having non-compliant meters as defined by the Australian Standards and Chapter 7 of the NER, but with no ability to recover the cost of replacing them through its charges. Ergon Energy should not be put in a position where it cannot fund the replacement of non-compliant meters. Clause 6.5.7(a)(2) of the NER requires that Ergon Energy's forecast capital expenditure must allow it to "comply with all applicable regulatory obligations or requirements associated with the provision of standard control services". Ergon Energy considers that this rule should apply equally to the provision of ACS given that the AER is applying a building blocks approach to determine charges for these services.

As a result, if the AER does not approve Ergon Energy's proposed replacement Capex, then it should provide an alternative mechanism for Ergon Energy funding the replacement of non-compliant meters over the 2015-20 regulatory control period so that it can continue to meet its regulatory obligations.

4.2.3. Capex forecasts

Ergon Energy has identified an error in the Capex forecasts that it included in its October Regulatory Proposal.

Table 4 of the *05.03.01 Default Metering Services Summary* (Type 5 & 6 meters) document that accompanied Ergon Energy's October Regulatory Proposal relates to "Forecast ACS default metering capital expenditure for 2015-20". While the total ACS default metering Capex numbers were correct, the table indicated that the direct cost Capex forecasts were in real 2014-15 dollars whereas, in fact, the forecasts were stated in real 2012-13 dollars.

This error arose from an administrative mistake in transposing the table and had the effect of under-estimating the direct costs metering Capex component and over-estimating the overheads component.

For transparency, Table 5 replicates the Table 4 of *05.03.01 Default Metering Services Summary* (which was mistakenly labelled "$m, real 2014/15").

Table 5: Metering Capex as presented in Ergon Energy's Default Metering Overview document ($M, Real $2012-13)

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Asset Replacement	7.3	7.3	7.3	7.3	7.3	36.3
Customer Initiated Capital Works	8.7	8.7	8.7	8.7	8.7	43.6
Other system Capex	0.5	1.1	0.9	0.2	-	2.7
Total ACS default metering Capex (direct costs only)	16.4	17.0	16.9	16.2	16.0	82.5
Overheads	8.2	8.8	9.7	9.8	9.9	46.4
Total ACS default metering Capex (direct costs & overheads)	24.7	25.9	26.6	25.9	25.9	128.9

Table 6 below details the correct version of the Capex forecasts that should have been included as Table 4 and therefore reflected into the October Regulatory Proposal. It correctly presents the forecasts in real 2014-15 dollars. The AER will note that the annual totals in each table are the same.

Table 6: Corrected metering Capex ($M, Real $2014-15)

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Asset Replacement	7.7	7.8	7.8	7.8	7.9	39.0
Customer Initiated Capital Works	9.3	9.3	9.4	9.4	9.4	46.8
Other system Capex	0.5	1.2	1.0	0.2	-	2.9
Total ACS default metering Capex (direct costs only)	17.6	18.3	18.2	17.4	17.3	88.7
Overheads	7.1	7.6	8.4	8.5	8.6	40.3
Total ACS default metering Capex (direct costs & overheads)	24.7	25.9	26.6	25.9	25.9	128.9

The above two tables simply seek to correct the information provided in our October Regulatory Proposal. Our revised metering Capex forecast for the 2015-20 regulatory control period, which takes account of the AER's proposed new fee structure - is detailed in our separate updated supporting document, *05.03.01 - (Revised) Default Metering Services Summary* (Type 5 & 6 meters).

4.2.4. Accelerated depreciation and recovery of residual metering capital costs

As noted above, Ergon Energy retains the view that it presented in its October Regulatory Proposal and in its 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 at the request of a customer.

Ergon Energy reiterated its rationale for this position in its letter to the AER dated 27 March 2015. The letter noted that an appropriately structured exit fee would:

- Give customers a clear cost signal to enable them to make well informed decisions about their choice of meter;
- Deliver an equitable user pays charging framework – the letter noted that there are many examples of exit fees in customer contracts, including retail energy contracts; and
- Lower the cost of providing services in the long term and create a complementary increase in competition at the point where suppliers compete for new customers.

However, if the AER maintains its proposal to not allow Ergon Energy to charge an exit fee then the next best alternative would be to allow Ergon Energy to accelerate the depreciation on its existing meters in order to recover its asset costs over five years. 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 AER's proposed approach.

The AER's proposed solution is to recover the costs from existing customers through a regulated annual capital charge which spreads the costs over an assumed 15 year remaining life. Ergon Energy considers that this approach will not promote efficient outcomes for customers. It would result in customers continuing to pay for meters over far too long a period of time. Customers will have long ago forgotten ever having had the meter and will continually be wondering why they are paying the additional charge. Indeed, there may be several changes of owner of a property over 15 years. Future in-coming owners, who never had any association with the original meter, will still be required to pay for it. This would create inequity between customers.

Our proposed alternative of a five year asset life promotes efficiency because it better aligns the recovery of the costs with the value the customer receives from the asset. Our reasoning is set out below:

- A five year asset life will increase the likelihood that the customer that used and benefited from the meter that is being removed will end up paying for it. This is because it decreases the possibility of a new occupant of a premise having to continue to pay the annual capital charge for that connection even though the existing meter has been replaced;
- In relation to SCS, the NER states that the "depreciation schedules must reflect the nature of the asset over the economic life of that asset"[9]. Given the introduction of competition through the proposed metering reforms, the economic life for existing meters will not be the standard technical life but rather the period until the meter is replaced. While this is difficult to predict, the AER's use of a 15 year asset life will only correctly match the economic life if no customer upgrades its meter. Therefore, an assumed asset life of five years will more likely approximate the economic life of these existing meters and would result in a charge which reflects the economic value to the customer of the meter;
- Clause 6.5.5(b)(1) of the NER provides that assets must be depreciated "using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets". Economic efficiency is maximised when the price of a service reflects the economic value of the assets used in providing that service (as measured by marginal cost) to the customer. For the reasons above, an accelerated depreciation approach is more likely to achieve this than a 15 year asset life because it is more likely to match recovery of the cost with the usefulness of the meter;
- Requiring customers to continue to pay for a meter after it has been replaced does not promote economic efficiency. In fact, it will contribute to confusion amongst customers and therefore probably involve additional administrative costs for retailers and distributors;
- Depreciating an asset past its useful (economic) life is not consistent with generally accepted tax or accounting principles;
- Applying accelerated depreciation would not create a regulatory barrier to competitive entry in advanced metering;[10] and
- The profile of annual charges under an accelerated depreciation solution is likely to encourage more customers to seek to upgrade their meter because after the five year depreciation period, customers would receive a reduction in their network charges which could be used to invest in better metering technology. This would more likely promote competition in advanced metering services, which is one of the factors that the AER must have regard to when determining the control mechanism for ACS.

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[9] NER, Clause 6.5.5 (b) (1)

[10] A potential problem with accelerated depreciation is that it could result in the asset owner being fully compensated for the asset while the asset remains in operation. This could create an incentive on the asset owner to inefficiently replace the asset earlier than required. However, Ergon Energy considers that this kind of incentive does not exist in these circumstances given the regulatory arrangements and the AER's proposal for up-front capital charges for new and replacement meters.

For these reasons, Ergon Energy proposes that the residual metering capital asset base is recovered over a five year period. This would enable Ergon Energy to recover its costs:

- Predominantly from the customer who benefited from the meters; and
- In a reasonable timeframe, whereby the affected customer can relate payment to the meter they asked to have replaced.

Ergon Energy thinks that it is far better to recover the residual meter costs as quickly as is reasonably possible from the customer that benefited from the meter, consistent with the efficiency principles of Chapter 6 of the NER. While this is best done through an exit fee, applying accelerated depreciation to determine an appropriate charge over five years would be a more efficient alternative than the AER proposed approach of recovering the costs over 15 years. As a result, Ergon Energy has not revised its Regulatory Proposal to reflect the AER's Preliminary Determination in relation to depreciation.

4.2.5. Opex base year

Ergon Energy prepared its ACS metering Opex forecast (totalling $169.5 million over the 2015-20 regulatory control period) under a base step trend (BST) approach using its BSTEY model. Ergon Energy:

- Chose 2012-13 as its base year;
- Applied a $1 million step change increase for preventative maintenance in 2015-16 to meet AEMO's requirements for meter testing and conformance to defined accuracy parameters; and
- Assumed a 1.6 per cent average annual real cost reduction over the 2015-20 regulatory control period.

The AER's Preliminary Determination reduced Ergon Energy's metering Opex by 30 per cent, or $50.9 million, from $169.5 million to $118.6 million (Real $2014-15) over the 2015-20 regulatory control period.

Despite Ergon Energy advising[11] that it was not suitable, the AER relied on Ergon Energy's economic benchmarking Regulatory Information Notice (EB RIN) data to prepare this revised Opex forecast. Ergon Energy understands that the AER used a five year (i.e. 2008-09 to 2012-13) historical average of EB RIN data to determine its five year forecast.

Ergon Energy considers that the AER has erred in applying the EB RIN data because this omits certain metering Opex. This is because components of the Opex for corrective maintenance and final meter reads for 2008-09 to 2012-13 were categorised as customer services (i.e. rather than metering) in the EB RIN Opex for network services.

This excluded Opex relates to metering services conducted for:

- Meter queries;
- Maintaining meter equipment (includes labour for replacing failed in-service meters);
- Alterations and additions of meters, including solar;[12] and
- Final meter reads.

Excluding this expenditure has understated Ergon Energy's ACS metering Opex. If it is not addressed in the AER's Final Decision it would mean that Ergon Energy is not funded to deliver

[11] Ergon Energy, Regulatory Proposal, 05.03.01 Default Metering Services, p22.
[12] Ergon Energy acknowledges that the costs associated with alterations and additions are now to be recovered through up-front charges.

essential metering services to its customers. Clause 6.5.6(a)(2) of the NER requires that Ergon Energy's forecast operating expenditure must allow it to "comply with all applicable regulatory obligations or requirements associated with the provision of standard control services". Ergon Energy considers that this rule should apply equally to the provision of ACS given that the AER is applying a building blocks approach to determine charges for these services.

Ergon Energy maintains its view that its BSTEY model provides the best basis for forecasting its Opex. BSTEY is the model that Ergon Energy has used to forecast its SCS Opex. By applying its Cost Allocation Method (CAM) (as approved by the AER), Ergon Energy ensures that there is an appropriate allocation of Opex between its SCS and ACS. The BSTEY model includes Opex relevant to the customer service activity excluded from the EB RIN Opex data utilised by the AER in its Preliminary Determination. The BSTEY forecast is explained in full in the revised Regulatory Proposal as part of Ergon Energy's justification of its SCS.

Using the BSTEY model, Ergon Energy's ACS metering Opex for 2015-20 is $182.61 million (Real 2014-15), as illustrated in Table 7 below.

Table 7: Revised Metering Opex - BSTEY ($M, Real 2014-15. Incl. O/H)

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Preventive Maintenance	3.46	3.61	3.75	3.84	3.93	18.59
Corrective Maintenance	1.92	2.00	2.07	2.12	2.17	10.28
Meter Reading	14.17	14.76	15.30	15.64	15.98	75.85
Customer Services	14.30	15.02	15.70	16.19	16.67	77.88
Total Metering Opex	**33.86**	**35.39**	**36.82**	**37.79**	**38.75**	**182.61**

Source: Ergon Energy, MT Escalations Data Model

The increase of $13.1 million from our original Regulatory Proposal is attributable to:

- The base year adjustments discussed in section 3.2.5 below; and
- Changes in our real cost escalations as explained in full in the revised Regulatory Proposal as part of Ergon Energy's justification of its SCS.

However, if the AER chooses to rely on Ergon Energy's EB RIN data then it would need to make significant adjustments to the metering Opex data originally submitted in the EB RIN.

In its EB RIN, Ergon Energy submitted a total Opex figure for metering services for 2008-09 to 2012-13 of $91.8 million (Nominal). However, when the services that have been excluded from these figures, as noted above, are included, it results in a total metering Opex of $214.2 million (Nominal). This is an increase of $122.4 million (Nominal) over the five years.

However, this $214.2 million (Nominal) then needs to be adjusted to account for the classification of services that will apply in 2015-20. This adjustment is a reduction of $79.5 million (Nominal). The revised total Opex for metering services for 2008-09 to 2012-13 that is consistent with the future metering classification would therefore be $134.7 million (Nominal) (i.e. not $91.8 million (Nominal) as proposed by the AER), or an average of $26.9 (Nominal) million over the five years.

A detailed build-up of these calculations is presented in Tables 8 to 11 below. We emphasise that the $134.7 million (Nominal) referred to above does not include escalators and is not comparable to Ergon Energy's proposed total Opex forecast of $182.61 million (Real, $2014-15).

Ergon Energy has not sought to use the adjusted EB RIN metering Opex data to prepare a revised Opex forecast for the next regulatory control period because:

- It is not clear from the AER's preliminary determination how it modelled its Opex forecast;
- Ergon Energy maintains its view that using a base-step-trend approach to forecasting Opex is more appropriate than using an historical five year average. An appropriately adjusted base year better reflects Ergon Energy's future requirements than an unadjusted historical five year average. This approach is consistent with how Ergon Energy has forecast its SCS Opex; and
- The EB RIN data that the AER has used does not reflect all of Ergon Energy's metering costs. As noted above, they exclude the costs of certain customer service activity.

Ergon Energy believes that its BSTEY model provides the best basis for forecasting its Opex. On this basis, its proposed total Opex forecast for metering for the next regulatory control period is $182.61 million (Real, $2014-15).

Table 8: EB RIN metering Opex provided to AER ($M, nominal)

Activity Code		2008-09	2009-10	2010-11	2011-12	2012-13	Total
52130	Preventive Reg Meters	2.14	2.36	3.34	2.74	3.12	13.69
53130	Corrective Reg Meters	1.63	3.72	1.86	2.20	2.33	11.74
56010	Network Metering	0.91	0.72	0.83	0.87	0.84	4.16
56020	Meter Reading Mass Market	12.23	11.71	11.90	13.24	12.66	61.73
56050	Revenue Protection Services	0.12	0.10	0.06	0.08	0.06	0.42
	EB RIN Total	**17.02**	**18.60**	**18.00**	**19.13**	**19.00**	**91.75**

Source: Reported EB RIN data

Table 9: Adjusted metering Opex inclusive of customer service Opex ($M, nominal)

Activity Code		2008-09	2009-10	2010-11	2011-12	2012-13	Total
	EB RIN Total (from above)	17.02	18.60	18.00	19.13	19.00	91.75
56000	Customer Installation Services	10.07	14.27	16.08	21.91	22.34	84.67
56200	Alternative Control Services	4.14	6.16	7.20	9.59	10.71	37.80
	Adjusted EB RIN Incl. all Metering Opex	**31.23**	**39.03**	**41.28**	**50.63**	**52.05**	**214.22**

Source: Reported EB RIN ACS Variation Model

Table 10: Metering Opex attributable to other ACS and SCS fees ($M, Nominal)

Activity Code		2008-09	2009-10	2010-11	2011-12	2012-13	Total
56000+ 56200	ACS Fee	3.27	4.43	4.59	4.95	4.26	21.50
	ACS Upfront	2.65	4.77	7.66	12.66	14.54	42.29
	SCS	2.38	3.36	3.03	3.71	3.24	15.73
	Base Adjustment for Daily Cost Calculation	**8.30**	**12.56**	**15.28**	**21.32**	**22.05**	**79.52**

Source: Reported EB RIN ACS Variation Model

Table 11: Adjusted metering Opex excluding Opex attributable to other ACS and SCS fees ($M, Nominal)

	2008-09	2009-10	2010-11	2011-12	2012-13	Total
Adjusted EB RIN Incl. all Metering Opex	31.23	39.03	41.28	50.63	52.05	214.22
Base Adjustment for Daily Cost Calculation	8.30	12.56	15.28	21.32	22.05	79.52
Adjustment metering Opex	**22.93**	**26.47**	**26.00**	**29.31**	**30.00**	**134.70**

Source: Reported EB RIN ACS Variation Model

4.2.6. Base year Opex adjustment

Ergon Energy's October Regulatory Proposal included a step change of $1 million for the costs of meter testing and conformance to defined accuracy parameters. The AER rejected this step change in its Preliminary Determination on the basis that it did not relate to a new regulatory obligation.

Ergon Energy agrees with the AER that it does not have any new regulatory obligation for meter testing. It was never Ergon Energy's intention to characterise its step change in this manner. Rather, Ergon Energy sought to identify existing regulatory requirements that are not provided for in its 2012-13 Opex base year.

There are two different existing regulatory requirements that are not recognised in the AER's allowance.

First, Ergon Energy needs to undertake in-situ sample testing of its meter families. During the 2005-10 and 2010-15 regulatory control periods, Ergon Energy did not undertake in-situ sample testing every year. Rather, it performed this testing between 2007 and 2010 and then again in 2014-15. As a result, Ergon Energy did not undertake any in-situ testing in 2012-13. Ergon Energy is proposing to change its testing regime by moving to an annual in-situ testing program to provide a more consistent volume for the program of works over the regulatory control period to improve resource planning as opposed to having spikes in volume.

Because Ergon Energy's October Regulatory Proposal used its 2012-13 Opex as its base year, its Opex forecasts did not include any allowance for recurrent in-situ testing. Ergon Energy now estimates the requirement for in-situ testing is 2,000 tests per annum at an estimated cost of $240 each for a total cost of $480,000 per annum. Ergon Energy has changed its base year in this revised Regulatory Proposal to 2013-14, however the same issue remains. It therefore proposes that this be treated as a one-off adjustment to its 2013-14 Opex base year.

Secondly, Ergon Energy has a 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. Again, this Opex was not included in its base year Opex. While the majority of the requirement has been completed in the 2010-2015 regulatory control period, Ergon Energy estimates that $20,000 per annum will be required to undertake this testing over the next regulatory control period.

As a result of these two matters, Ergon Energy has made a base year adjustment of $500,000 to its Opex metering forecast.

If the AER does not accept the need to make these two adjustments to Ergon Energy's base Opex then this will impede our ability to meet our testing obligations under the NER and deliver an efficient service to our customers. As noted above, Ergon Energy believes that clause 6.5.6(a)(2) of the NER that requires that Ergon Energy's forecast operating expenditure must allow it to "comply with all applicable regulatory obligations or requirements associated with the provision of standard control services" should apply equally to the provision of ACS given that the AER is applying a building blocks approach to determine charges for these services.

4.3. Metering charges

4.3.1. Upfront capital charges for new and replacement meters

This section addresses specific concerns that Ergon Energy has with the AER's proposed upfront capital charges for new and replacement meters and proposes alternative positions that Ergon Energy believes better meet the NER requirements and the long-term interests of its customers.

General concerns with AER's approach

The AER's preliminary decision proposes two types of metering service charges:

- An upfront capital charge for all new and upgraded meters installed after 1 July 2015; and
- An annual charge comprising a capital component for existing meters and a non-capital component.

Figure 1 above illustrates how the AER proposes that these charges be applied to new and existing connections.

Ergon Energy wrote to the AER on 22 May 2015 opposing an upfront charge being levied on customers to recover the full capital cost of new or replacement meters. Ergon Energy explained that the metering charges that it had set out in its October Regulatory Proposal were consistent with the AER's Framework and Approach paper, had benefited from consultation with customers and other stakeholders and could readily be implemented by 1 July 2015 with minimal changes seen by customers. In contrast, the AER's Preliminary Determination departed from the Framework and Approach paper based on expectations of a forthcoming NER change for metering contestability.

As it explained in its letter of 22 May, Ergon Energy is concerned that:

- The AER has effectively dismissed Ergon Energy's customer and stakeholder engagement and does not appear to have undertaken any alternative consultation to support the imposition of the upfront capital charge;

- The upfront capital charge will further impede customers choosing new services such as cost reflective tariff options, installing solar photovoltaic systems and adopting controlled load tariffs. This is because these options require a meter installation or upgrade to a new meter. Therefore under the AER proposal, these customers will be required to pay both the upfront meter cost plus the installation costs to access these services;
- Customers will respond negatively to the imposition of an upfront charge, which will increase complaints to Ergon Energy and enquiries to the Energy Ombudsmen; and
- Ergon Energy has a very limited timeframe to communicate this change to its customers, retailers and electrical contractors before the charges take effect from 1 July 2015.

As an alternative, Ergon Energy proposed that a transitional arrangement apply during which time:

- There would be no upfront charge for a transitional period (of six to 12 months) in order to enable appropriate engagement with customers, retailers, electricians and other stakeholders;
- New and upgrading customers will be charged the same meter service fee as applies to the equivalent existing customers; and
- Ergon Energy and the AER reconcile the Capex arising from the transition and the AER adjust its final decision accordingly.

The AER responded to Ergon Energy's letter on the 15 June 2015 stating that:

- The current NER constrains the AER's ability to approve a deviation from its determinations;
- Where a distribution determination has been made, a Distribution Network Service Provider's pricing proposals must implement the determination;
- Pricing proposals must be compliant with the applicable distribution determination;
- The AER must approve a pricing proposal if it is satisfied that it complies with the applicable distribution determination; and
- The AER would require Ergon Energy to charge for regulated type 5 and 6 electricity meters upfront rather than amortising the charge over the economic life of the meters, as is the current practice.

Ergon Energy remains opposed to the AER's proposed structure for metering charges. In the following sections, Ergon Energy has addressed specific concerns that it has with the AER's proposed upfront charges. It should not be interpreted that by commenting on specific issues about the upfront charges, that Ergon Energy is in any way resiling from its general opposition to the AER's proposed charging framework. Rather, the following sections detail the clarifications and changes that Ergon Energy considers are necessary to ensure that the upfront charges fully recover the efficient cost of providing the service if the AER choose to retain its approach in its Final Determination. Adopting (despite not endorsing) the AER's proposed structure for metering charges reflects the practical reality that Ergon Energy needs to apply the charges in the Preliminary Determination from 1 July 2015. This in turn requires Ergon Energy to implement system changes and to engage with stakeholders about its charges. Changing these charges again in 2016-17 would involve further system changes and could create confusion amongst our customers.

Nature of upfront charges

In its October Regulatory Proposal (and classification proposal) for the next regulatory control period, Ergon Energy referred to all Type 5 and 6 metering installation, provision, maintenance, reading and data services as 'ACS Default Metering Services'.

However, the AER's proposal to introduce upfront capital charges requires a change in what is covered by 'ACS Default Metering Services'. This is addressed in Ergon Energy's revised classification proposal.[13] Ergon Energy is now proposing that:

- 'Default Metering Services' should be limited to:
  - Type 5 and 6 meter installation and provision (before 1 July 2015);
  - Type 5 and 6 meter installation and provision (on or after 1 July 2015) where the replacement meter is initiated by the distributor; and
  - Type 5 and 6 metering maintenance, reading and data services.
- Type 5 and 6 meter installation and provision (on or after 1 July 2015) required as a result of a customer request – that attracts upfront capital charges – should be classified as part of 'Other ACS' and no longer included in 'Default Metering Services'.

Distinction between upfront capital charges during and after business hours

Table 16.15 of Attachment 16 of the Preliminary Determination details the AER's proposed upfront charges for Ergon Energy's single phase, dual element and three phase meters. The AER explains that it derived these charges based on a build-up of materials, labour and capital allowances.

This cost build-up is similar (but inconsistent in some aspects) to that used for fee-based and quoted services. Therefore in this revised Regulatory Proposal Ergon Energy is treating the upfront charge for new and replacement meters as a fee based service for business hours services and as a quoted service for after-hours services, rather than as part of the Default Metering Service annual charge. This allows a consistent formula and approach to be used for all services priced using a cost build-up approach.

The inputs, assumptions and models used in the development of the upfront charges are set out in the following sections of our documentation suite:

- 05.05 Other Alternative Control Service Key Documents;
- 05.06 Other Alternative Control supporting documentation and references.

As noted above, Ergon Energy has developed proposed upfront charges despite disagreeing in-principle with this charging policy.

AER's proposed materials allowance is too low

Ergon Energy considers that the AER's proposed allowance for the materials component of the upfront capital charge is too low for all three of the AER's proposed meter categories and is insufficient to cover the efficient cost of the services. There are three reasons for this:

1. Ergon Energy's understanding is that the costs in Table 15 of Appendix 4 from the Marsden Jacobs' report[14] represents the raw hardware meter material costs for meters. They therefore exclude any stores on-cost or overheads. The AER has made no other provision in its proposed charges for Ergon Energy to recover these additional costs. Ergon Energy has reflected these costs in its proposed upfront charges;
2. The AER has stated in the Preliminary Determination that it has derived the materials costs from the 'top end' of the estimates set out in Table 5 of the Marsden Jacobs report.[15] While this is true

[13] Refer document 02.02.01 - (Revised) Classification Proposal

[14] Marsden Jacobs - Provision of advice in relation to Alternative Control Services

[15] AER Preliminary Determination for Ergon Energy, Attachment 16, section 16.2.5.3.2 page 48.

for the single phase single element and dual element meters it is not so for three phase meters, which is at the bottom end of Marsden Jacob estimated meter cost and below Ergon Energy's current purchase cost. The AER's proposed material cost allowance for a three phase meter is $189.27. The AER based this amount on advice from Marsden Jacobs. Table 15 of Appendix 4 of Marsden Jacobs' report contains a table that details a range of market rates for Type 5 three phase meters from $189.27 to $220. Ergon Energy's proposed upfront charges are based on costs at the 'top-end' of estimates for all meter types; and

3. Recent exchange rate movements have resulted in a 7 per cent increase in material costs, which are not reflected in Marsden Jacobs' cost estimates which was published in October 2014. The AER's approved material cost allowance should reflect these exchange rate movements. Ergon Energy has reflected these costs in its proposed upfront charges.

Unless the AER adjusts the charges in its Final Determination to address these three matters it will prevent Ergon Energy from recovering the efficient costs to deliver these customer-initiated metering installations consistent with the pricing principles in the National Electricity Objective.

Separate charge for LVCT meters

Ergon Energy has connected approximately 1,000 LVCT meter installations annually in the 2010-15 regulatory control period. It expects to continue to need to install LVCT meters in new and replacement situations in the 2015-20 regulatory control period.

However, the AER has not made any specific provision in Table 16.15 of Attachment 16 of its Preliminary Determination for Ergon Energy levying a separate upfront capital charge for the provision and installation of LVCT meters, associated CTs, test terminals and fuse kit and commissioning by a two person crew.

In contrast, the AER did make a specific provision for CT meters in Table 16.26 of Attachment 16 of its Preliminary Determination for Energex.

Ergon Energy has prepared upfront charges for new and replacement three phase LVCT meters, associated CTs, test terminals and fuse kit and commissioning by a two person crew for each year of the 2015-20 regulatory control period, using the fee based services formula.

These are the charges that should apply when Ergon Energy levies an upfront charge for new and replacement three phase CT meters in the 2015-20 regulatory control period. As discussed in the section below entitled 'Different meter charges by feeder type', Ergon Energy considers that there needs to be different fees for different feeder type to recognise the different costs of servicing urban and rural installations.

Different meter charges by feeder type

There are significant differences between the labour costs that Ergon Energy incurs in providing its services to its customers across its vast service area. This is predominantly a result of higher travel and access costs for rural installations. It is therefore appropriate for Ergon Energy to levy different charges depending on whether the customer is serviced from Ergon Energy's urban / short-rural feeders or long-rural / remote feeders. The AER has recognised these differences in:

- Approving Ergon Energy's other fee based and quoted service charges for the 2010-15 regulatory control period; and
- Its Preliminary Determination for Ergon Energy's fee based service charges.

In both of these instances, there are differences in Ergon Energy's charges for its services across feeder types.

The AER has not recognised these different costs in its Preliminary Determination for Ergon Energy's metering charges. Instead, the AER is proposing that the upfront charges in Table 16.15 of Attachment 16 of its Preliminary Determination be applied uniformly across Ergon Energy's service area. This means that the AER has proposed to apply a flat labour installation cost for both rural and urban customers.

The AER's approach is inconsistent with promoting cost-reflective pricing. It would result in significant cross-subsidies between customers across Ergon Energy's service area and prevent clear price signals being sent to customers.

If the AER requires Ergon Energy to levy upfront capital charges for installing or upgrading meters then separate charges should be developed for Ergon Energy's single phase, dual element, three phase and CT meters depending on whether the customers are serviced from urban / short rural feeders or long rural / remote feeders.

Ergon Energy has prepared up-front charges for each year of the 2015-20 regulatory control period using the formula for fee based services consistent with other ACS prices. These charges are detailed in the following sections of our documentation suite:

- 05.05 Other Alternative Control Service Key Documents; and
- 05.06 Other Alternative Control supporting documentation and references.

AER's misunderstanding of quoted services

The AER made a distinction in the 2010-15 regulatory control period between Ergon Energy's ACS by treating some as "fee based services" and others as "quoted services":

- Fee based services involve setting fixed prices in advance; whereas
- Quoted services involve using the AER's approved formula to develop a specific charge every time a customer requests a job.

In setting the prices for upfront charges for metering, the AER has indicated in its Preliminary Determination that it has reviewed Ergon Energy's prices for quoted services and assessed that, as Ergon Energy only has one price per service, it can set a single price for each metering service.

Ergon Energy is concerned that the AER has misunderstood that the quoted service prices that Ergon Energy submitted in its October Regulatory Proposal were examples only to demonstrate compliance with the AER's quoted service formula.[16] They were never intended to represent the single price that Ergon Energy could charge for its services, given that, by their nature, quoted services would need to be developed for each customer. The problem with the AER's Preliminary Determination is that it effectively involves treating Ergon Energy's examples of its quoted service prices as fixed fee based services.

It is not appropriate for the AER to set a single price for each type of meter. This would not enable Ergon Energy's charges to vary between customers to reflect their different costs of supply.

Ergon Energy is proposing to address this need for cost variances by having:

- Fixed fee-based service charges that vary by meter type and by feeder type for customers that request services during business hours; and
- Quoted service charges for individual customers that request after hours services.

[16] 05.05.01 – Inputs and Assumptions for Alternative Control Services

4.3.2. Annual capital and non-capital charges

Ergon Energy does not support the AER's proposed charging framework for default metering services based on annual capital and non-capital charges. We maintain the view set out in our October Regulatory Proposal that an exit fee is the most equitable mechanism for recovering residual metering costs.

Without in any way resiling from this general opposition to the AER's proposed charging framework, Ergon Energy has reflected the Capex and Opex changes that it has proposed in section **Error! Reference source not found.** above into its proposed annual capital and non-capital charges in the event that the AER choose to retain its approach in its Final Determination. These include changes in relation to Ergon Energy's:

- Cost of aged asset replacement;
- Residual metering capital costs;
- Efficient Opex; and
- Cost of capital.

Ergon Energy notes that it has needed to apply the AER's Preliminary Determination to set its actual annual capital and non-capital charges for 2015-16. This requirement, combined with the inadequate annual revenue allowances (discussed above) that Ergon Energy considers the AER has made in its Preliminary Determination, create an issue for recovering the required revenue over the next regulatory control period. In order to address this issue, Ergon Energy has needed to adapt its MT Pricing Model to calculate prices for the last four years under two scenarios:

- reflecting the fact that the 2015-16 prices from the Preliminary Determination are to be implemented from 1 July 2015, such that prices for the remaining four years need to be adjusted in order to recover the required revenue; and
- Assuming the transitional arrangements in the NER do not apply such that it is the Final Determination (rather than the Preliminary Determination) that sets prices for 1 July 2015.

Ergon Energy's MT Pricing Model presents the results of both modelling scenarios.

4.4. Rate of return parameters

Ergon Energy does not accept the substitute cost of capital and gamma values that the AER has used in its Preliminary Determination to determine the annual revenue requirements for its metering services for the 2015-20 regulatory control period.

The reasons for not accepting these values are the same as those that it has given in the revised Regulatory Proposal for not accepting the AER's substitute cost of capital and gamma values for SCS.

Ergon Energy proposes the same cost of capital and gamma values be applied to its metering services, as it proposes for its SCS.

Ergon Energy also notes that we have used the January 2015 version of the Post Tax Revenue Model (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 SCS.

4.5. 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.

As noted above, 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 SCS. If it does, this will need to be incorporated into the X factors for the Default Metering Services.

5. Other revisions

Ergon Energy has made a number of changes to our proposal on Default Metering Services since October 2014. This section outlines our key revisions and provides a list of the changes.

5.1. Key revision

5.1.1. Change to base year

Ergon Energy has updated its base year to 2013-14 as this reflects the latest year of audited accounts. This is consistent with our approach to SCS.

5.1.2. Updated inputs

Ergon Energy has updated several inputs underlying the calculation of revenue for Default Metering Services. In particular, we have revised:

- Our forecast overhead rates, in line with our CAM.
- Our forecast inflation consistent with our approach to SCS

Our forecast real cost escalators. Ergon Energy has applied the escalators provided by Jacobs[17] in our pricing models.[18]

5.1.3. Rate of return

Ergon Energy has updated its WACC and gamma forecasts consistent with its approach to SCS.

5.2. List of changes

Table 12 sets out the other revisions we have made to our October Regulatory Proposal and supporting documents.

Table 12: Revisions to our Regulatory Proposal and supporting documents in relation to other factors influencing our Default Metering Services

Document	Section/Table	Revision
05.03.01 Default Services Summary	All	• Document updated to reflect revision of nature of default metering services given proposed new upfront capital charges and changes in building block components set out in this document
05.04.06 – Engineering Report Meter Replacement Program	11.1.2 – End of life Asset Replacement	• Updated to include recent testing results of Warburton Franki Model: WF2 • Updated to include additional justifications for replacement of Ferranti Model TM2c meter family
05.05.01 – Inputs and assumptions for Alternative Control Services	Table 1	• Updated to reflect new fee based services for metering
	Section 4.1	• Deleted the reference to Materials not being used in the delivery of fee based services, given the new metering services

[17] Refer to *06.02.07 – Jacobs: Addendum Cost Escalation Factors 2015-20*.
[18] It is important to note Ergon Energy has not updated the nominal escalators applying in 2015-16. These escalators were approved by the AER in the Preliminary Determination and the 2015-16 Pricing Proposal.

Document	Section/Table	Revision
	Table 5	• Added new metering services (including a column for material costs)
	Table 10	• Added an indicative price for the new quoted service relating to the installation and provision of meters after hours
05.06.02 – Fee based services model	All	• Added the new fee based services for metering and the relevant assumptions. This necessitated the inclusion of a ‘Materials’ section in the ‘Inputs’ tab and a revision to the ‘Materials’ description in the ‘Fee based services formula’ tab
05.06.03 – Quoted services model	All	• Added the new quoted service for metering and the relevant assumptions

Supporting documents

The following documents support our response to the AER:

Name	Ref
(Revised) Default Metering Services Summary	05.03.01
(Revised) Inputs and Assumptions for Alternative Control Services	05.05.01
(Revised) ACS Pricing Inputs	05.06.01
(Revised) Fee based services model	05.06.02
(Revised) Quoted services model	05.06.03

Definitions, acronyms, and abbreviations

[This section contains definitions for all acronyms, technical terms, and abbreviations used in the document.

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ACS	Alternative Control Service
BSTEY	Ergon Energy's Base Step Trend model
CAM	Cost Allocation Method
Capex	Capital expenditure
CT	Current Transformer
CPI	Consumer Price Index
EB RIN	Economic Benchmarking Regulatory Information Notice
Ergon Energy	Ergon Energy Corporation Limited
FL	Full Load
LL	Light Load
LVCT	Low Voltage Current Transformer
MAB	Metering Asset Base
NER	National Electricity Rules
Opex	Operating expenditure
PTRM	Post Tax Revenue Model
Repex	Replacement expenditure
SCS	Standard Control Service
WACC	Weighted Average Cost of Capital