05.03.01

Default Metering Services Summary (Type 5 & 6 meters)

Contents

1. Introduction

1.1 Purpose

The purpose of this Default Metering Services Expenditure Summary is to present Ergon Energy's proposed prices for its Alternative Control Services (ACS) default metering services for the 2015-20 regulatory control period.

This document updates an earlier version of this document that was provided to the Australian Energy Regulator (AER) with Ergon Energy's Regulatory Proposal. This update has been developed having regard for:

- The AER Preliminary Determination on Ergon Energy's Regulatory Proposal that was issued in April 2015; and
- The re-classification of Types 5 and 6 metering services, from Standard Control Services (SCS) to ACS, in the AER's Framework and Approach (F&A) paper for Queensland Distribution Network Service Providers (DNSPs).

Ergon Energy's use of the term "ACS default metering services' in this document, and in its revised Regulatory Proposal, refers 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.

This definition is different to what Ergon Energy proposed in its Regulatory Proposal. This is because in its Preliminary Determination the AER decided that the provision and installation of Type 5 and 6 meters on or after 1 July 2015 as a result of a customer request should attract an upfront charge. These services are to be classified as part of 'Other ACS' and are no longer included in default metering services. Ergon Energy has set out further information about its proposed upfront capital charges in the following documents:

- *Submission to the AER on its Preliminary Determination – Metering; and*
- *Submission to the AER on its Preliminary Determination – Alternative Control Services – Other*

1.2 Scope

Following the re-classification of Type 5-6 metering services by the AER, Ergon Energy needs to develop separate prices for its ACS default metering services. This document outlines Ergon Energy's approach to developing ACS default metering prices, having regard for the matters raised in the AER's Preliminary Determination.

This document should be read in conjunction with other metering-related documents that Ergon Energy has provided with its Revised Regulatory Proposal, including the document entitled *Submission to the AER on its Preliminary Determination Metering.*

1.3 Summary of default metering services charges

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. Ergon

Energy continues 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 adopt the proposal set out in this document.

Ergon Energy has updated its October Regulatory Proposal to reflect:

- revised asset replacement expenditure to reflect the removal of capital expenditure (Capex) associated with new and replacement meters
- The 2013-14 base year for operating expenditure (Opex)
- Updated inputs including overhead rates, inflation, escalators, the Weighted Average Cost of Capital (WACC) and gamma
- Capital and non-capital charges for recovery of the costs associated with the default metering service

Ergon Energy's proposed annual capital charges recover its return on capital and depreciation attributable to its default metering services. These charges have been calculated based on $71.82 million (real $2014-15) in capital expenditure (Capex) for the next regulatory control period. This comprises $34.92 million for asset replacement, $10.54 million for customer initiated capital works (failed in service meters), $2.6 million in other Capex for field based meter configuration capability and $23.75 million in Capex overheads.

Ergon Energy's proposed annual non-capital charges recover its Opex and tax allowance attributable to its default metering services.

2. Regulatory requirements

Ergon Energy's metering prices for the 2015-20 regulatory control period are regulated under Chapter 6 of the National Electricity Rules (NER), which concerns the economic regulation of distribution services and which sets out the terms of the AER's review, including the process and timing. A series of Rule change proposals are currently being considered by the Australian Energy Market Commission (AEMC), as proposed by the AEMC in its Power of Choice review[1]. The AEMC released its Draft Determination on 26 March 2015. However, the AER is already aligning its approach as though the Council of Australian Governments' (COAG) rule change request regarding metering services were in effect[2].

Ergon Energy's ACS default metering services are subject to regulatory requirements outlined in the NER, the AER's F&A Paper, the AER's Expenditure Forecast Assessment Guideline and the Australian Energy Market Operator's (AEMO) Metrology Procedures, along with Queensland specific legislative requirements (as found in the Queensland Electricity Distribution Network Code). Applicable regulatory requirements for the provision of ACS default metering services by Ergon Energy are outlined below.

2.1 National Electricity Rules

The NER specifies the national regulatory framework for classifying regulated services, controlling service pricing and determining prices. This framework is applied by the AER in determining Ergon Energy's proposed prices for ACS default metering services.

2.1.1 Service classification and price control

The AER regulates a variety of services provided by Ergon Energy as a DNSP. Under Chapter 6, Part B of the NER, the AER may classify a distribution service as either a direct control or a negotiated service. Direct control services can be further classified as SCS or ACS. In classifying a service, the NER requires the AER to be consistent with their previous classification unless a different classification is more appropriate[3].

The AER makes a determination to control either the revenue or prices (or both) of direct control services. The basis of the control mechanism is the method used to calculate the revenue to be recovered or prices to be set for a group of services. Whilst the control mechanism for SCS must be in the form of CPI-X (or some other incentive-based variant of this approach), there is no constraint on the control mechanism for ACS, other than that its basis must be stated in the distribution determination[4]. The AER is able to apply a control mechanism to ACS as set out under Chapter 6, Part C of the Rules (Building Block Determinations for SCS[5]). This involves applying the building block approach, although the AER may choose only to apply certain elements of this approach or, alternatively, it may implement a control mechanism that does not use the building block approach[6].

[1] AEMC, *Final Report, Power of Choice Review – giving consumers choice in the way they use electricity*, 30 November 2012
[2] AER, *Final Framework and Approach for Energex and Ergon Energy – Regulatory control period commencing 1 July 2015*, April 2014, Appendix C – Rule requirements for Classification
[3] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 6.2.2 (d)
[4] Ibid, Clause 6.2.6 (b)
[5] Ibid, Clause 6.2.6 (c)
[6] AER, *Final Framework and Approach for Energex and Ergon Energy – Regulatory control period commencing 1 July 2015*, April 2014, Section 2.4, p65

In the past, however, the approach adopted by the AER for determining ACS prices has differed little from the approach adopted for SCS prices[7]. Given the relative level of expenditure involved, the AER's review of ACS default metering services may be less extensive than their review of SCS. However, Ergon Energy nonetheless expect a rigorous review, noting the potential for the determination to impact the development of competition in ACS default metering services.

2.1.2 Determining annual revenue requirements

Where the AER chooses to make an ACS determination on the basis of a building blocks approach, the AER must specify the annual revenue requirement for each year based on the following building blocks[8]:

- Indexation of the regulatory asset base (RAB)
- A return on capital for that year
- The depreciation (return of capital) for that year
- The estimated cost of corporate income tax of the DNSP for that year
- The forecast operating expenditure (Opex) for that year.

Indexation of the RAB involves the addition of approved Capex, the subtraction of depreciation and the indexation of the asset base using the AER's Roll Forward Model (RFM)[9].

The AER must approve Ergon Energy's proposed Capex and Opex forecast included in a building block proposal if the AER is satisfied that the Capex and Opex forecasts are[10]:

- The efficient costs of achieving the Capex and Opex objectives
- The costs that a prudent operator would require to achieve the Capex and Opex objectives
- A realistic expectation of the demand forecast and cost inputs required to achieve the Capex and Opex objectives.

2.1.3 Distribution pricing rules

Once each of the building blocks has been determined, they are used as inputs into the Post Tax Revenue Model (PTRM) to determine Ergon Energy's annual revenue requirement. The allowed revenue is then recovered through tariffs proposed each year by Ergon Energy, for the AER's assessment under the Network Pricing Rules.

The AER must approve a regulatory pricing proposal if satisfied that the proposal complies with Part 1 of Chapter 6 of the NER. The key pricing requirements from Part 1 which are relevant to this Metering Proposal relate to the design of tariff classes, design of tariff components and recovery of allowed revenue.

With regards to the design of tariff classes, tariff classes must group customers together on an ''economically efficient basis", avoiding unnecessary transaction costs and with ACS tariff classes separate to SCS tariff classes. Each customer must be a member of at least one tariff class[11].

[7] This is illustrated, for example, in the AER's Final Determination for SA Power Networks (formerly ETSA Utilities) for the 2010-15 period. See: AER, *Final decision South Australia distribution determination 2010-11 to 2014-15*, May 2010, pp 254-274
[8] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 6.4.3 (b)
[9] Ibid, Clause 6.4.3 (b) (1)
[10] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p6
[11] AEMC, *National Electricity Rules*, Version 71, April 2015, Clause 6.18.3

Under the Pricing Principles contained within the NER, the revenue to be recovered by each tariff class should lie on or between[12]:

- An upper bound representing the standalone cost of serving the retail customers who belong to that class
- A lower bound representing the avoidable cost of not serving those retail customers.

Where a tariff consists of two or more charging parameters, the price for each parameter must take into account the Long Run Marginal Cost (LRMC) of providing the service, having regard to the associated transaction costs and customers' ability and likelihood to respond to price signals. Residual costs are to be recovered in a manner that minimises distortion of efficient service consumption.

2.2 The AER's Framework and Approach Paper

The AER is required to publish an F&A paper at the commencement of each regulatory determination period under Clause 6.8.1 of the NER. The F&A is the first step in determining efficient prices for distribution services and sets out the AER's proposed approach on which services to regulate, the classification of distribution services, the form of the control mechanism and formulae to give effect to the control mechanism (or mechanisms).

2.2.1 Service classification and control

The AER's F&A for Energex and Ergon Energy[13] for the regulatory control period commencing 1 July 2015, set out its intention to re-classify Type 5 and Type 6 metering services from SCS to ACS. This re-classification means that metering services are no longer part of a bundled charge for SCS, but that customers pay a cost reflective charge based on the meter installed.

The F&A also stipulated the AER's proposed approach on the form of the control mechanism. For ACS, the AER proposed the use of price caps on individual services so as to provide cost reflective benefits.

The AER's F&A specified ACS metering services to include the following sub-services[14]:

- Meter installation
- Meter provision – selection, procurement, programming, testing and management of National Metering Identifier (NMI) standing data according to the NER
- Meter maintenance – scheduled maintenance, meter inspection, removal of meter and meter tampering
- Meter reading – refers to quarterly or other regular reads of meters
- Meter data services – collection, processing, storage and delivery of metering data, remote or self-reading at difficult to access sites, provision of metering data from the previous two years, ongoing provision of metering data.

The AER's F&A established the control mechanism and the formula for Ergon Energy's different services. For metering the AER established a price cap form of control and formula to apply.

[12] Ibid, Clause 6.18.5 (a)
[13] AER, *Final framework and approach for Energex and Ergon Energy – Regulatory period commencing 1 July 2015*, April 2014
[14] Ibid, p114

The AER's Preliminary Determination indicates that it has maintained the ACS classification for Type 5 and 6 metering services set out in its F&A and also maintained that the control mechanism for ACS will be caps on the prices of individual services.

2.3 The AER's Expenditure Forecast Assessment Guideline

The AER is required to publish an Expenditure Forecast Assessment Guideline (the Guideline) for DNSPs under Clause 6.2.8 of the NER. The Guideline specifies the approach the AER proposes to use to assess a DNSP's Capex and Opex forecasts and the information the AER requires to make its assessment[15].

To assess Ergon Energy's proposal, the AER will apply a range of techniques to determine whether proposed expenditures are efficient. These assessment techniques include:

- Economic benchmarking
- Category level analysis
- Predictive modelling
- Trend analysis
- Cost benefit analysis
- Project review
- Methodology review
- Governance and policy review.

The AER's general approach is to assess the efficiency of a DNSP and determine whether previous spending is an appropriate starting point[16]. The AER expects that Ergon Energy will propose costs that a prudent operator would require to achieve the expenditure objectives under the NER and that this prudent and efficient expenditure represents the lowest long term cost to consumers for the most appropriate investment or activity required[17].

2.4 AEMO's Metrology Procedure

AEMO is required under Clause 7.14.1 of the NER to publish a Metrology Procedure[18], which includes jurisdictionally specific metrology material[19]. The Queensland specific requirements in AEMO's Metrology Procedure are contained within Section 2 and include the following key derogations:

- Queensland metering providers (including Ergon Energy) are not to install Type 5 metering installations, as for any Type 5 metering installations, the volume of electricity to flow through the relevant connection point is to be 0 MWh p.a[20]
- First tier customers who consume up to 750 MWh p.a. can continue to use a Type 6 meter[21]

[15] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p4
[16] AER, *Better Regulation factsheet: Expenditure forecast assessment guideline*, November 2013
[17] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p9
[18] AEMO, *Metrology Procedure: Part A National Electricity Market*, July 2012
[19] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 7.14.2
[20] AEMO, *Metrology Procedure: Part A National Electricity Market*, July 2012, Section 2.4.16
[21] AEMO, *Metrology Procedure: Part A National Electricity Market,* July 2012, Section 2.4.18

- For Type 6 metering installations, Ergon Energy must ensure that metering installations are interval meters capable of being upgraded for use in a Type 4 metering installation without replacing the meter[22]
- Ergon Energy must ensure interval meters are not replaced by accumulation meters[23]
- A remotely read interval meter can only be replaced by a manually read Type 6 interval meter if consumption drops below 100 MWh p.a.[24]
- Energy consumed and measured by a Type 6 interval meter must be settled in the wholesale electricity market on the basis of a Type 6 metering installation[25].

Based on the above jurisdictional derogations for Queensland in AEMO's Metrology Procedure, Ergon Energy has installed Type 6 meters in its distribution network.

2.5 Proposed future regulatory changes

Currently, the Queensland DNSPs are the monopoly providers of Type 5 and 6 metering services[26]. However, the AER has noted that Type 5 and 6 metering services are likely to become open to more competition in the future[27]. This is consistent with the AEMC's Power of Choice Review final report, which recommended the provision of metering services be contestable and that measures to promote contestability in Type 5 and 6 metering services be pursued[28]. Based on the AEMC's recommendations, the COAG Energy Council submitted a Chapter 7 rule change request in October 2013 to enable competition in metering services.

The COAG Energy Council considers that the current regulatory arrangements are inhibiting commercial investment in metering technologies and has proposed changes to the NER to implement arrangements that would support a competitive market for the provision of metering services.

The COAG Energy Council highlights that any new arrangements for the competitive provision of metering services should be simple and practicable from a consumer's perspective. Ultimately, it will be up to consumers to make choices based on the benefits they perceive will be provided by end use services. The benefits to the network system will be realised through the choices consumers make[29].

AEMC released a Consultation Paper[30] on the proposed Rule change in April 2014 and, following public consultation, released a Draft Determination in March 2015 under which the proposed new Rule would provide for the:

- Establishment of a national framework for metering competition
- Creation of a new, independent Metering Coordinator role
- Separation of this role from the network and retailer roles and allowing customer choice
- Unbundling of metering service charges from Distribution Use of System (DUoS) charges

[22] Ibid, Section 2.4.18
[23] Ibid, Section 2.6.1
[24] Ibid
[25] Ibid
[26] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 6.2.2 (c) (1)
[27] AER, *Final framework and approach for Energex and Ergon Energy – Regulatory period commencing 1 July 2015*, April 2014, p11
[28] AEMC, Final Report, Power of Choice Review – giving consumers choice in the way they use electricity, 30 November 2012, p83
[29] AEMC, *Consultation Paper – National electricity amendment (expanding competition in metering and related services) Rule 2014*, April 2014, p iii
[30] AEMC, *Consultation Paper – National electricity amendment (expanding competition in metering and related services) Rule 2014*, April 2014

- Specification of minimum services that a new or replacement meter installed at a small customer's premises must be capable of providing
- Circumstances in which small customers may opt out of having a new meter installed at their premises
- Entitlement of parties to access energy data and metering data to reflect the changes to roles and responsibilities of parties providing metering services
- Use by local network service providers (LNSPs) of network devices installed at customers' premises to assist them to monitor and operate their networks
- Setting of customer transfer (exit) fees for existing regulated meters by the AER
- Requirement that pre-existing load management arrangements be supported when replacing meters
- Requirement that AEMO maintain the national minimum functional specification for smart metering.

Importantly, the proposed rule change would allow the states to determine the following key policy and regulatory settings on a jurisdictional basis:

- Minimum functionality requirements for new connections and replacement metering
- Allowing reversion to lower functionality metering
- Extension of metering monopolies, e.g. Type 7.

The AEMC indicated on 2 July 2015 that it expects the implementation date for the new Chapter 7 of the NER will be 1 December 2017.

3. AER's Preliminary Determination

The AER's Preliminary Determination indicates that it has maintained the ACS classification for Type 5 and 6 metering services set out in its F&A and that the control mechanism for ACS will be caps on the prices of individual services.

The Preliminary Determination approved two types of metering service charges:

- Upfront capital charge for all new and replacement meters installed from 1 July 2015
- Annual charge comprising two components:
    - Capital – metering asset base (MAB) recovery
    - Non-capital – Opex and tax recovery.

Figure 1 below replicates Figure 16.3 from the AER's Preliminary Determination that depicts how the AER's proposed two regulated annual charge components relate to different metering customers.

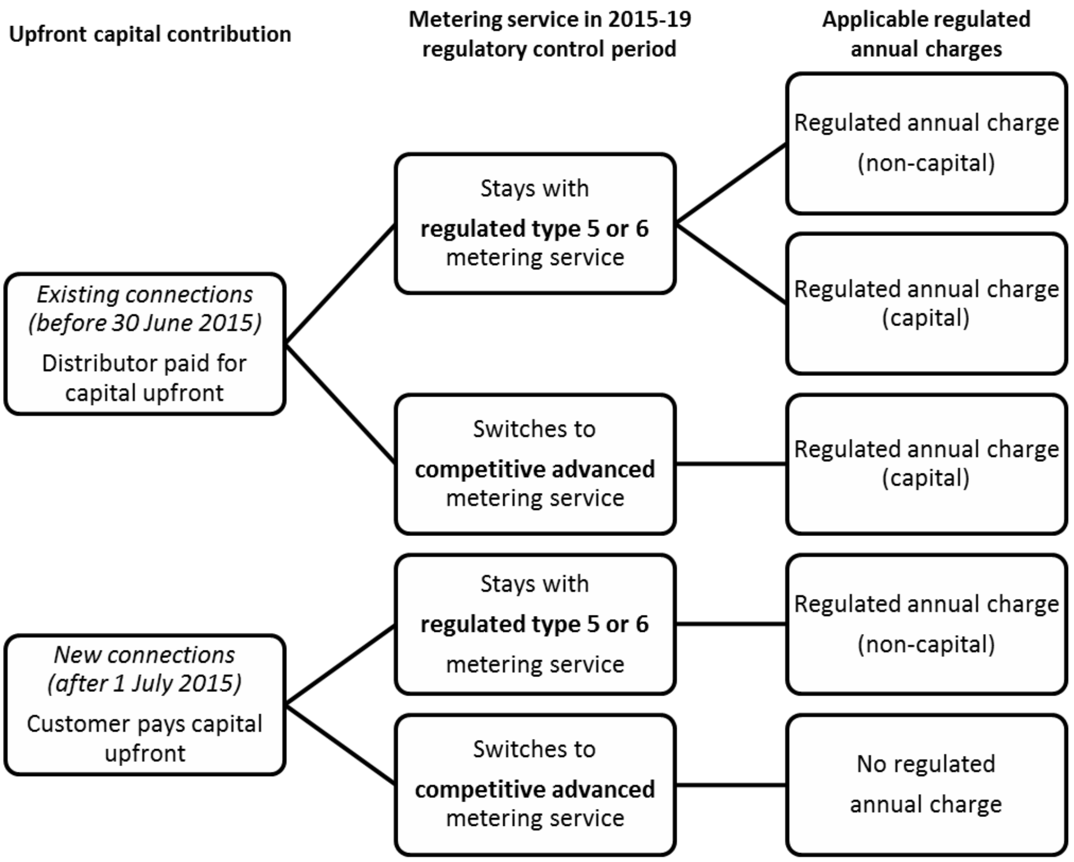

Figure 1: Preliminary Determination – applicable regulated annual charges

This figure illustrates that under the AER's Preliminary Determination:

- Customers with existing connections installed before 1 July 2015 who receive a regulated type 5 or 6 metering service would pay the:
    - Capital (MAB recovery) component of the regulated annual metering charge
    - Non-capital (Opex and tax) component of the regulated annual metering charge.
- Customers with existing connections installed before 1 July 2015 who choose to switch from a regulated type 5 or 6 metering service to a competitive advanced metering service would pay the:

  - Capital component of the regulated annual metering charge
  - Any charges payable to their competitive metering provider for advanced metering services.

  This structure applies even if a customer pays upfront for a meter upgrade to their existing regulated meter after 1 July 2015.

- New customers after 1 July 2015 who receive a regulated type 5 or 6 metering service would pay the:
  - Capital cost of their meter upfront
  - Non-capital component of the regulated annual metering charge
- New customers after 1 July 2015 who switch to a competitive advanced metering service (and no longer receive a regulated type 5 or 6 metering service) stop paying all regulated annual metering charges and only pay charges levied by their competitive metering provider for advanced metering services.

The AER's Preliminary Determination:

- Calculated its upfront capital charge based on the labour and materials cost of installing the meter plus a capital allowance. The AER calculated different charges for single phase (single element), (single phase) dual element and three phase meters
- Calculated the annual capital and non-capital charges using a building blocks approach. The AER approved:
  - An opening MAB value as at 1 July 2015 of $60.7 million instead of Ergon Energy's proposed $61.6 million
  - Standard asset lives of 15 years instead of Ergon Energy's proposal to apply accelerated depreciation of three years for newly installed meters and five years for pre-existing metering assets
  - The use of forecast depreciation
  - Capex of $51.3 million instead of Ergon Energy's proposed $128.9 million (real $2014-15)
  - Opex of $118.6 million instead of Ergon Energy's proposed $169.5 million (real $2014-15)
- Rejected Ergon Energy's proposal to levy an exit fee on customers who choose to move to another metering provider if competition is introduced for type 5 and 6 metering services.

4. Capital expenditure

This section presents Ergon Energy's Capex proposal relevant to its annual capital charges for default metering services for the 2015-20 regulatory control period and demonstrates its prudency, efficiency and reasonableness, as required under Section 6.5.7(c) of the NER.

Ergon Energy's ACS metering Capex program is broken up into asset replacement, customer initiated capital works (CICW), other system Capex and overheads. The material costs associated with meter corrective maintenance are treated as Capex. The labour installation costs for corrective maintenance are treated as Opex.

This section covers the relevant regulatory requirements, Ergon Energy's key policies and assumptions impacting the metering Capex proposal, historical Capex trends and forecast Capex.

In summary, Ergon Energy is proposing $71.82 million ($2014-15) in Capex relevant to its annual capital charges for its ACS default metering services for the 2015-20 regulatory control period. This comprises $34.9 million in asset replacement (end of life, in-situ non-compliant meter families and obsolete meter technology), $10.54 million in customer initiated capital works, $2.6 million in other system Capex for in field meter configuration capability and $23.75 million in Capex overheads.

4.1 Key regulatory requirements

4.1.1 National Electricity Rules

Under the Rules for SCS expenditure, the AER is required to approve Ergon Energy's proposed Capex forecasts if it is reasonably satisfied that forecast Capex is[31]:

- The efficient cost of achieving the Capex objectives
- The cost a prudent operator would require to achieve the Capex objectives
- A realistic expectation of the demand forecast and cost inputs required to achieve the Capex objectives.

Ergon Energy has structured this proposal on the expectation that the AER will undertake the same approach to the assessment of ACS as to SCS.

4.1.2 AER's Capex assessment approach

The AER intends to assess forecast Capex proposals against the NER by using a combination of top down and bottom up approaches[32], with a focus on determining the prudent and efficient level of forecast Capex. The AER will assess the need for the expenditure and the efficiency of proposed projects (including consideration of the timing, scope and scale of proposed projects).

For a DNSP to show that its Capex forecast is efficient and prudent, the AER expects the DNSP to demonstrate that overall expenditure will result in the lowest sustainable cost (in present value terms) to meet the legal obligations of the DNSP. If Ergon Energy claims higher levels of investment than those required to meet their legal obligations, the AER requires a demonstration that the investment represents the highest net present value of all viable options.

[31] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 6.5.7 (c)
[32] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p17

Assessment of Capex may include explicit consideration of productivity change over time (based on historical Capex) and the AER may benchmark Ergon Energy's historical Capex productivity changes with other DNSPs. The AER will likely use top down economic benchmarking to compare Ergon Energy's performance with that of other DNSPs[33]. The AER has indicated that its approach to both Capex and Opex assessment will place greater reliance on economic benchmarking than it has in the past[34].

4.1.3 AEMO's Metrology Procedure

Under Part A of AEMO's Metrology Procedure, Ergon Energy is a Metering Provider, registered with AEMO, with responsibility for metering installations[35].

As a registered Metering Provider, Ergon Energy must ensure that all meters installed meet the requirements of Section 2.4 of the Metrology Procedure, which includes any guidelines specified by the National Measurement Institute and contained within the *National Measurement Act*, as well as any applicable specifications and guidelines contained within Australian or International Standards[36].

Under the Metrology Procedure, Ergon Energy is required to provide new metering assets at premises that are either new or upgraded and consume less than 750 MWh p.a. for first tier customers, or less than 100MWh p.a. for second tier customers[37]. Importantly, Type 6 metering installations provided by Ergon Energy as their standard business as usual meter must be capable of a being upgraded for use as a Type 4 (smart meter) metering installation[38].

In terms of Ergon Energy's Meter Asset Management Plan (MAMP), the following requirements under the Metrology Procedure apply:

- The MAMP must comply with the meter inspection and testing requirements under Chapter 7 of the NER, unless AEMO approves an alternative method[39]
- An acceptable testing practice to measure in-situ compliance of meters will demonstrate compliance with Australian Standards for in-service compliance testing[40]
- The MAMP is required to document testing and inspection requirements[41], and must include description of an accuracy assessment method[42]
- The MAMP must be submitted to AEMO for approval[43].

Ergon Energy's MAMP demonstrates compliance with these requirements and has received approval by AEMO.

[33] Ibid, p14
[34] Ibid, p12
[35] Ergon Energy's responsibilities as a Metering Provider are documented in Section 2 of AEMO's Metrology Procedure
[36] AEMO, *Metrology Procedure: Part A National Electricity Market*, July 2012, Section 2.4.1, p30
[37] AEMO, *Metrology Procedure: Part A National Electricity Market*, July 2012, Section 2.4.18
[38] Ibid
[39] Ibid, Section 2.7.3
[40] Ibid, Section 2.7.4
[41] Ibid, Section 2.7.5
[42] Ibid, Section 2.7.6
[43] Ibid, Section 2.7.8

4.2 Key policies and assumptions

4.2.1 Capex Forecasting Approach

Ergon Energy's forecasting approach for ACS default metering Capex is consistent with the approach it has applied to forecast Capex for SCS services. The approach to forecasting Capex for both ACS default metering and SCS services involves forecasting direct costs in the expenditure categories of Asset Replacement[44], CICW[45] and Other System Capex and applying escalation and overheads to these direct costs using the same approach.

4.2.2 Cost allocation methodology

Ergon Energy incurs costs for metering services, which must be allocated between ACS and SCS. Capex is also subject to corporate overheads, which are allocated in accordance with Ergon Energy's Cost Allocation Method (CAM).

Ergon Energy's CAM was approved by the AER in June 2014 for the 2015-20 regulatory control period. The CAM sets out Ergon Energy's allocation of costs between regulated and unregulated services, as well as between SCS and ACS categories. Ergon Energy's approach to allocating Capex to ACS default metering services is outlined in the supporting documentation[46].

4.2.3 Capital contributions

Ergon Energy is not proposing to apply capital contributions for ACS default metering services in the 2015-20 regulatory control period. This is because a new upfront capital charge has been introduced for new and replacement meters.

4.2.4 Metering solution

The proposed policy for new connections and replacement metering is to use polyphase meters on all multi-phase installations and single phase meters (single element or dual element) where a primary or secondary tariff is required. This will reduce the overall meter asset quantities on existing installations. All residential meters will be installed with import/export displays to cater for the large penetration of solar photo-voltaic (PV) systems.

The proposed metering strategy[47] recognises the changing regulatory environment and market framework, due to the advent of advanced (or ''smart'') metering. The proposed policy is therefore that all new, upgrade and replacement meter installations will be capable of meeting the new national minimum metering specification when it is released. Ergon Energy is also planning a targeted deployment of smart meters for network operational purposes where the benefits exceed the costs. For example, high cost service areas including difficult to access sites.

In light of jurisdictional requirements specified in the Metrology Procedure and the likely move to smart metering over the next five to ten years, Ergon Energy's metering policy is to progressively procure meters with contactors and internal power supply for communications modules.

[44] Ergon Energy, *07.00.01 – Asset Renewal Capital Expenditure Forecast Summary*
[45] Ergon Energy, *07.00.03 – Customer Initiated Capital Works Expenditure Forecast Summary*
[46] Ergon Energy, *Cost Allocation Method - Version 4.0 - AER Approved*
[47] Ergon Energy, *Metering Vision and Strategy, October 2014*

To reduce the costs to customers for a future competitive metering arrangement, Ergon Energy is expecting that some of its meters (that meet the minimum specification) will be capable of upgrading to advanced metering simply by adding a communications module.

In relation to load control, Ergon Energy's current practice is to install ripple receivers with 1 relay and provision for 3 switches to accommodate for load control of multiple devices. As the load control is part of the SCS, Ergon Energy will continue to utilise a standard device for load control so that the network retains this capability, should a meter be replaced in a contestable rollout. Ergon Energy's proposed policy is to continue with its current practice. However, we may consider alternatives based on the regulatory environment, cost/benefit analysis and other factors.

4.2.5 Meter replacement

Ergon Energy's meter replacement policy is to replace multiple meters used for multi-phase installations with a single polyphase meter and to use single phase, two element meters to support sites with separately metered controlled load tariffs where practical.

"End of life'' replacement is based on meter assets that are twice their "economic life" and display characteristics of failure. This assumes replacement of electro-mechanical meters after 50 years (standard lifetime of 25 years) and electronic metering equipment after 30 years (standard lifetime of 15 years).

The AER's Preliminary Determination accepted the replacement of four meter types and rejected the replacement of the other two meter types. Ergon Energy maintains that it should replace its:

- Ferranti Type TM2c meters because they are a small meter family that is more than 50 years old, has an expected increase in failure rates and the cost to replace the meters is similar to the cost of performing onsite testing
- Warburton Franki (Type WF2) meters because Ergon Energy is now confident this meter family will be confirmed non-compliant on completion of the current 2014-15 in-situ testing program

The accompanying document *Submission to the AER on its Preliminary Determination - Metering* provides further information about Ergon Energy's justification for replacing these two meter types.

4.2.6 Competition assumptions

Ergon Energy is assuming no material competition in metering services will occur over the 2015-20 regulatory control period. This assumption enables Ergon Energy to forecast its capital expenditure requirement based on historical trends and relationships, without the need to estimate the rate of meter churn and level of competition.

It is assumed that the introduction of competition through a Rule change process will constitute a regulatory change event under Clause 6.6.1(a)(1) of the NER, and that the associated cost implications for network billing, network pricing and the range of ACS default metering services (e.g. final reads, etc.) will be considered at that time via a regulatory pass through.

In that event, Ergon Energy would be required to submit to the AER a written statement within 90 business days of becoming aware of the regulatory change event, outlining the costs Ergon Energy believes should be passed onto consumers. The AER would then assess these forecast costs and make a determination on Ergon Energy's cost pass through application, taking into account relevant factors under Clause 6.6.1(j) of the NER.

4.3 Historical capital expenditure

Ergon Energy's metering Capex over the 2010-15 regulatory control period was largely embedded in its SCS proposal. The AER has developed reporting guidelines over the period, which specifically separate out metering Capex into a number of Capex categories. However, these categories are not aligned to the AER's proposed service classification, nor are they mutually exclusive and collectively exhaustive. Ergon Energy has therefore developed reasonable estimates of historical Capex that align to its forecasts in order to enable comparison.

Tables 1 to 3 present Ergon Energy's actual and estimated installations, unit prices and total annual Capex by driver over the 2010-15 regulatory control period.

Table 1 below shows historical direct costs (excluding overheads) for ACS default metering in the 2010-15 regulatory control period. ACS default metering overheads were not recorded for Type 5 and 6 metering services in the 2010-15 period as these services were bundled in with other SCS network services, however they will be recorded for the forecast period to align with the reclassification of these metering services from SCS to ACS.

Table 1: ACS default metering Capex for 2010-15 ($m, Nominal)

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Planned Meter Replacements	0	0	0	0.03	3.86	3.89
Corrective Maintenance (Failed in Service)	1.38	1.22	1.61	1.47	1.67	7.35
Total ACS default metering Capex (direct costs only)	**1.38**	**1.22**	**1.61**	**1.50**	**5.53**	**11.24**

Source: Ergon Energy, based on volumes from Ellipse CIS Service Order Data – Financial Year Reports, unit costs from CICW Metering – ACS, CICW Services - ACS and planned meter replacements programs.

Overall, Ergon Energy's direct ACS default metering Capex (without overheads) over the current five year regulatory control period is estimated to be $11.2 million, based on actual Type 5 and 6 metering Capex unit costs in 2012-13, extrapolated for the rest of the 2010-15 regulatory control period using actual meter installation volumes in each year. The metering Capex in 2014-15 is based on estimated volumes and unit costs.

The volume of planned meter replacements was slowed in the earlier years of the 2010-15 regulatory control period due to the significant uptake of solar PV installations, uncertainty around smart meter policy and available metering asset data information. The significant uptake of solar reduced the number of sites with BAZ meters that required replacement. The planned meter replacement program was also put on hold due to uncertainty around the future policy and regulatory framework, in particular the smart meter agenda. At the start of the 2010-15 regulatory control period it appeared that there was going to be a large-scale rollout of advanced metering infrastructure in Queensland. The replacement program was also slowed as Ergon Energy had to run an asset data program to identify the location of BAZ meters due to their age and poor legacy records.

Ergon Energy recommenced replacing non-compliant meter families in 2014-15 and will continue these planned replacement programs in the 2015-20 regulatory control period. The volumes of service orders and meter replacements for planned meter replacements and corrective maintenance for 2010-15 are shown below in Table 2.

Table 2: ACS default metering installation volumes for 2010-15

	2010-11	2011-12	2012-13	2013-14	2014-15	2010-15
Planned Meter Replacements Service Orders	-	-	-	56	12,377	**12,433**
Planned Meter Replacements Meters	-	-	-	56	12,377	**12,433**
Corrective Maintenance Service Orders	23,869	50,097	34,078	20,439	33,333	**161,816**
Corrective Maintenance Meters	9,062	7,898	10,226	9,062	10,000	**46,248**
Total ACS default metering services orders	**23,869**	**50,097**	**34,078**	**20,495**	**45,710**	**174,249**
Total ACS default meter installations and replacements	**9,062**	**7,898**	**10,226**	**9,118**	**22,377**	**58,681**

Source: Ellipse CIS Service Order Data – Financial Year Reports.

Ergon Energy's ACS default metering unit prices for the 2010-15 regulatory control period are based on actual 2012-13 Type 6 costs, as shown in Table 3. The high planned replacement unit cost in 2013-14 was due to a trial of BAZ meter replacement costs in Dalby as part of Ergon Energy's assessment of in-house versus outsourced costs of providing metering services.

Table 3: ACS default metering unit prices for the 2010-15 ($Nominal)

	2010-11	2011-12	2012-13	2013-14	2014-15
Planned Meter Replacements (Labour & Materials)	-	-	-	482	312
Corrective Maintenance (Materials)	152	154	158	163	167

Source: Ergon Energy, unit costs from CICW Metering – ACS, CICW Services – ACS and planned meter replacement programs.

4.4 Forecast capital expenditure

Ergon Energy's forecast Capex for the 2015-20 regulatory control period presented in Table 4 is based on the forecast volumes of metering installations per annum, the forecast unit price per installation and forecast overhead costs over the period. The detailed assumptions underpinning Ergon Energy's volumes and unit price forecasts are detailed below, along with a demonstration of the deliverability of Ergon Energy's proposed metering ACS default capital program.

Table 4: Forecast ACS default metering capital expenditure for 2015-20 ($m, real 2014/15)

	2015-16	2016-17	2017-18	2018-19	2019-20	Total 2015-20
Asset Replacement	7.03	7.03	7.01	6.96	6.89	**34.92**
Customer Initiated Capital Works - Metering	2.10	2.11	2.12	2.11	2.10	**10.54**
Other System Capex	0.48	1.05	0.90	0.18	0.00	**2.62**
Total ACS default metering capital expenditure (direct costs only)	**9.61**	**10.19**	**10.03**	**9.25**	**8.99**	**48.08**
Overheads	4.08	4.77	5.09	4.89	4.92	**23.75**
Total ACS default metering capital expenditure (direct costs & overheads)	**13.69**	**14.96**	**15.12**	**14.14**	**13.91**	**71.82**

Source: Ergon Energy, individual cost categories in RIN format sheet of MTCapex Data Model and Total ACS default metering Capex in Input sheet of MTPTRM Data Model.

Overall, Ergon Energy forecasts its direct Capex (without overheads) attributable to its annual capital charges for its default metering services to be $48.1 million (real $2014-15), compared with current period Capex of $11.2 million. The key driver of the increase in ACS default metering Capex is the $31.0 million increase in the planned meter replacement program.

The CICW program includes Capex for the costs of failed-in-service meters. The forecast does not include Capex attributable to new customer connections or additions and alternations. This is because Ergon Energy will levy up-front capital charges in the next regulatory control period for new and replacement meters in accordance with the AER's Preliminary Determination.

The Other System Capex category includes the cost of hand held devices and associated capability needed for in field configuration management[48].

Capex Overheads were calculated using Ergon Energy's PTRM. Ergon Energy do not forecast metering IT separately as it is provided by SPARQ, the common IT provider to Ergon Energy and Energex, and allocated to metering via the overheads cost allocation process.

4.4.1 Forecast volumes

Ergon Energy's volume forecasts for metering installations are based on its forecast corrective, end of life and obsolete meters in its Meter Asset Management Plan. It is Ergon Energy's view that the forecasting methodologies applied in both cases are based on industry best practice and are consistent with the Guidelines[49].

[48] Ergon Energy, *Meter Configuration Management System Report*, February 2014
[49] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p17

Table 5 – Forecast ACS default metering installation volumes for 2015-20

	2015-16	2016-17	2017-18	2018-19	2019-20	2015-20
Planned Meter Replacement Service Orders	24,944	24,944	24,944	24,944	24,944	**124,720**
Planned Meter Replacement Meters	24,944	24,944	24,944	24,944	24,944	**124,720**
Corrective Maintenance Service Order	32,833	32,833	32,833	32,833	32,833	**164,165**
Corrective Maintenance Meters	9,850	9,850	9,850	9,850	9,850	**49,250**
Total ACS default metering services orders	**57,777**	**57,777**	**57,777**	**57,777**	**57,777**	**288,885**
Total ACS default meter installations	**34,794**	**34,794**	**34,794**	**34,794**	**34,794**	**173,970**

Source: CICW Services - ACS, Reg Reset RIN forecast model,

The significant increase in the meter replacements in the 2015-20 period is based on the replacement of meters that have reached the end of their life, non-compliant meter families and obsolete technology, developed in accordance with AEMO requirements. This is discussed in section 4.2.5 and the accompanying document *Submission to the AER on its Preliminary Determination - Metering*.

Although the forecast of 173,970 meter installations over the 2015-20 period is higher than the 2010-15 regulatory control period, Ergon Energy considers that this forecast volume of metering installations is deliverable without significant changes to its current delivery model, which includes a panel of metering service providers to support the internal capability in delivering metering replacement programs.

Ergon Energy's forecast breakdown in the number of meters by meter type are based on historical ratios, and are presented in Table 6. This ratio is assumed in the meter volume forecasts and the associated unit prices.

Table 6 – Forecast metering equipment ratios

Meter Type	Mix
1 Phase	30%
2 Element	56%
3 Phase WC	12%
3 Phase CT	2%

Source: Ergon Energy, Metering asset data.

4.4.2 Unit prices

Ergon Energy's unit prices forecast for metering installations are based on competitively let contracts for specified metering solutions and field services, historical installation support, fleet, tools and site remediation costs, and historical rates of internal field labour productivity.

Table 7 presents estimated unit prices over the next five years by installation driver. Price estimates reflect the bottom-up budgeting process used in the replacement business case divided by the number of installations. While metering technology prices are expected to decline, this is expected to be muted by the use of fixed price contracts to access volume discounts.

Table 7 – Forecast ACS default metering installation unit prices (real $2014-15)

	2015-16	2016-17	2017-18	2018-19	2019-20
End of Life Meters (Labour & Materials)	291	291	290	288	285
In-situ Driven Non-Compliant Meter Families (Labour & Materials)	291	291	290	288	285
Obsolete Meter Technology (Labour & Materials)	221	221	220	219	217
Corrective Maintenance (Materials)	178	179	181	182	184

Source: Ergon Energy, unit costs from CICW Metering - ACS and planned meter replacement programs.

Ergon Energy's material unit prices are based on a mix of meter types required for various metering configurations, as per Table 6 above. The unit cost for the asset replacement programs (e.g. the end of life and in-situ driven non-compliant meter families) allows for factors such as project management, mobilisation costs and minor switchboard remediation (e.g. meter isolation links). Meter costs in the proposed replacement programs are based on changing out single element meters.

By specifying solutions and services that are future proof and integrating market resources where the market can provide services more cost effectively, Ergon Energy is of the view that these unit prices are efficient and prudent, and reasonably likely to occur over the forecast period.

5. Operating expenditure

This section presents Ergon Energy's Opex proposal for ACS default metering for the 2015-20 regulatory control period and demonstrates its prudency, efficiency and reasonableness, as required under Clause 6.5.6(c) of the NER.

This section covers the relevant regulatory requirements, Ergon Energy's key policies and assumptions impacting its Opex proposal, historical Opex trends and forecast Opex using the AER's base, step and trend (BST) approach.

In summary, Ergon Energy is proposing $182.6 million ($2014-15) in ACS default metering Opex over the 2015-20 regulatory control period including $60.5 million for Opex overheads.

5.1 Key regulatory requirements

5.1.1 National Electricity Rules

Under the NER, the AER is required to approve Ergon Energy's proposed Opex forecasts as included in a building blocks proposal if it is reasonably satisfied that the Opex forecasts reflect[50]:

- The efficient cost of achieving the Opex objectives
- The cost a prudent operator would require to achieve the Opex objectives
- A realistic expectation of the demand forecast and cost inputs required to achieve the Opex objectives.

5.1.2 AER's Opex assessment approach

Ergon Energy's Opex for its default metering services is almost entirely recurrent. As a result, the AER preference is to apply a "base-step-trend'' (BST) approach to assessing Opex[51].

Under this approach, the base year expenditure is assessed to determine whether it is a reasonably prudent and efficient starting point, using the range of criteria described above. Any identified (material) inefficiencies will be used to adjust the base year to an efficiency benchmark base year.

The "revealed cost" approach is the AER's preferred approach to assessing base year Opex. If the AER finds that actual Opex in the base year reasonably reflects the Opex criteria, the base year Opex will be set to actual expenditure for those cost categories, using the revealed cost approach.

Step changes typically reflect structural shifts in the cost of supply, for example due to changes in the regulatory environment or the impact of an efficient investment on operational expenditure[52]. They can be due to both positive and negative change events, and therefore may be added or subtracted for any other costs not captured in the base Opex or rate of change that are required for the forecast Opex to meet the Opex criteria. If it is efficient to substitute Capex with Opex, a step change may also be included for these costs, i.e. Capex/Opex trade-offs.

The trend is estimated using the historical change in output costs as a function of input prices, productivity and output quantities.

[50] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 6.5.6 (c)
[51] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p22
[52] Ibid, p24

The AER notes that, when appropriate, it will assess Opex forecasts using other techniques (determined on a case-by-case basis), or other techniques in combination with the base-step-trend approach, if this will produce an Opex forecast more consistent with the Opex criteria[53].

5.2 Key policies and assumptions

5.2.1 Cost allocation method

For the 2015-20 regulatory control period, Ergon Energy's ACS default metering operating costs include:

- Preventative maintenance
- Corrective maintenance
- Meter reading
- Customer services
- Opex overheads

Preventative maintenance is mainly comprised of time based metering equipment testing for direct connected and complex Type 6 installations.

Corrective maintenance includes asset refurbishment, laboratory services and metering asset disposal expenditure.

Meter reading includes quarterly or other regular default meter reading, including internally triggered check reads. It excludes special reads which are classified as ACS quoted services. Opex associated with remotely read Type 6 meters for operational reasons is separately estimated, but reported in the overall meter reading Opex.

Customer services includes all other services related to ACS metering Opex, including meter investigations and queries (mixed allocation between ACS default metering and ACS quoted services), failed meter replacement, maintaining broken meter seals, maintenance of meter testing equipment and final reads.

Opex overheads includes meter data services costs, IT Opex and business overheads.

Ergon Energy has assumed a 60 per cent allocation of meter data costs to ACS default metering, with the remaining costs allocated to SCS and Type 1-4 metering. The 60 per cent allocation to ACS default metering is based on a proportional break up of staff and systems used for the provision of Type 6 meter data services.

Ergon Energy's ACS default metering categories map to the AER F&A approach categories of meter maintenance, reading, data services and Opex overheads as shown in Table 8 below.

[53] Ibid, p22

Table 8: Mapping of Ergon Energy's ACS default metering Opex categories to AER F&A categories

AER Framework and Approach	Ergon Energy
Meter Reading	Meter Reading
	Customer Services – ACS (Final Reads)
Meter Maintenance	Preventative Maintenance - ACS
	Corrective Maintenance - ACS
	Customer Services – ACS (Maintain Meters)
Meter Data Services	Operating Expenditure Overheads
Operating Expenditure Overheads	Operating Expenditure Overheads

Source: AER Final Framework and Approach Paper for Energex and Ergon Energy – Regulatory control period commencing 1 July 2015 (April 2014) and Ergon Energy analysis.

5.2.2 Opex Forecasting Approach

Ergon Energy has adopted a BST methodology to forecast its ACS default metering expenditure. This is a change from the bottom-up forecasting approach that it adopted for the current regulatory control period.

5.2.3 Service Classification

Ergon Energy's policy for the forthcoming regulatory period is to treat all costs associated with new and replacement meters at customer request as an ACS fee based service for work performed during business hours work and a quoted service for after hours work.

5.2.4 Capitalisation

Ergon Energy's policy is to treat the labour costs associated with corrective meter maintenance as Opex.

5.3 Historical operating expenditure

The AER's Regulatory Information Notice (RIN) specifically separates out metering expenditure into a number of Opex categories; however these categories are not aligned to the AER's service classification, nor are they mutually exclusive and collectively exhaustive. Ergon Energy has adjusted its historical Opex represented in the RIN in the manner discussed below.

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 Economic Benchmarking Regulatory Information Notice (EB RIN) Opex for network services. The AER used this information to determine its Opex forecast for the next regulatory control period. However, this excluded metering services Opex related to services conducted for:

- Meter queries
- Maintaining meter equipment (includes labour for replacing failed in-service meters)

- Alterations and additions of meters, including solar[54]
- Final meter reads.

Excluding this expenditure has understated Ergon Energy's historical ACS metering Opex.

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).

A detailed build-up of these calculations is presented in Table 9 below. The table also shows Ergon Energy's EB RIN Opex for metering services in 2013-14 included the Customer Service Opex relating to metering.

Table 9: Development of Adjusted metering Opex ($M, Nominal)

	2008-09	2009-10	2010-11	2011-12	2012-13	2008-09 to 2012-13 Total	2013-14
Submitted EB RIN	17.02	18.60	18.00	19.13	19.00	**91.75**	51.99
Adjusted metering Opex inclusive of customer service Opex	14.21	20.43	23.28	31.50	33.05	**122.47**	0
Adjusted EB RIN Incl. all Metering Opex	**31.23**	**39.03**	**41.28**	**50.63**	**52.05**	**214.22**	**51.99**
Base Adjustment for Daily Cost Calculation	8.30	12.56	15.28	21.32	22.05	**79.52**	19.40
Adjusted metering Opex	**22.93**	**26.47**	**26.00**	**29.31**	**30.00**	**134.70**	**32.59**

Source: Reported EB RIN ACS Variation Model

5.4 Forecast operating expenditure

5.4.1 Opex forecast

Table 10 presents Ergon Energy's forecast Opex for the 2015-20 regulatory control period.

[54] Ergon Energy acknowledges that the costs associated with alterations and additions are now to be recovered through up-front charges.

Table 10: Forecast ACS default metering Opex for 2015-20 ($M, real $2014-15)

	2015-16	2016-17	2017-18	2018-19	2019-20	2015-20
Preventive Maintenance	2.43	2.46	2.49	2.51	2.54	**12.43**
Corrective Maintenance	1.35	1.36	1.37	1.39	1.40	**6.87**
Meter Reading	9.95	10.06	10.15	10.24	10.33	**50.72**
Customer Services	10.04	10.23	10.41	10.59	10.78	**52.06**
Total ACS default metering Opex (Direct Costs only)	**23.77**	**24.11**	**24.42**	**24.73**	**25.05**	**122.08**
Opex Overheads	10.09	11.28	12.40	13.06	13.70	**60.53**
Total ACS default metering Opex (incl. O/H)	**33.86**	**35.39**	**36.82**	**37.79**	**38.75**	**182.61**

Source: Ergon Energy, MTOpex Data Model, RIN format sheet.

These forecasts were developed using a BST methodology[55], which consists of:

- selecting a base year – Ergon Energy has chosen 2013-14 as its base year
- making appropriate adjustments for non-recurrent items
- making any further adjustments required to establish an efficient base year
- applying an appropriate trend[56].

Ergon Energy has calculated its Opex forecasts in the MTOpex Data Model which uses Ergon Energy's BSTEY model as an input. These models have been provided to the AER with the revised Regulatory Proposal.

By projecting future Opex from the 2013-14 base year's revealed costs and trends in productivity, Ergon Energy is of the view that its proposed Opex forecast is efficient and prudent, and reasonably likely to occur over the forecast period.

5.4.2 Base Year

Ergon Energy considers that the AER has erred in applying the EB RIN data to forecast its Opex because, as noted above, 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);
- Final meter reads.

Excluding this expenditure has understated Ergon Energy's ACS metering Opex. If it is not addressed in the AER's final determination it would mean that Ergon Energy is not funded to deliver essential metering services to its customers.

[55] ACS default metering overheads were not applied using the BST approach as they are allocated based on direct costs.
[56] Ibid, p31

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 Methodology, 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. The BSTEY forecast is explained in full in our Revised Regulatory Proposal as part of Ergon Energy's justification of its SCS.

Ergon Energy has chosen 2013-14 as its base year as this is the most recent financial year for which audited regulatory accounts were available.

Ergon Energy has made two adjustments to its base year Opex from what it submitted in its Regulatory Proposal. These relate to:

- A change in its testing regime to move 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. Ergon Energy's 2012-13 Opex did not include any allowance for recurrent in-situ testing
- 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 National Electricity Rules. Again, this Opex was not included in its original base year model.

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

6. Regulatory asset base

This section presents Ergon Energy's approach to carving out the ACS default metering opening MAB from the SCS opening RAB for the 2015-20 regulatory control period and presents the resulting depreciation and capital costs estimated using the AER's RFM.

In summary, Ergon Energy's estimated ACS default metering opening MAB is $61.6 million (real $2014-15). By the end of the regulatory control period, Ergon Energy estimates the ACS default metering MAB will have reduced to $29.0 million.

6.1 Key regulatory requirements

The NER requires Ergon Energy's RAB, where used in a building blocks determination, to be based on the starting RAB and the AER's RFM[57].

The RAB refers to the value of assets used by Ergon Energy to provide services and must be calculated in accordance with Clause 6.5.1 of the NER. Establishing a starting ACS default metering opening MAB requires the carving out of ACS default metering assets from the SCS RAB.

The NER requires costs to be allocated according to an AER approved CAM, which must comply with the principles outlined in Clause 6.15.2. In order to be approved, the CAM must allocate costs on a causal basis or, if that isn't possible, in a manner that does not distort efficient competition.

In accordance with Clause 6.5.5 of the NER, depreciation for each regulatory year must be calculated based on the value of assets included in the RAB. This value is to be proposed by Ergon Energy in a depreciation schedule which conforms to the following requirements[58]:

- It reflects the economic life of that asset or category of assets.
- It is equivalent to the value of assets when first entered into the RAB.
- It is consistent with depreciation of equivalent assets on a prospective basis.

Clause 6.5.2 of the NER requires that the return on capital be determined such that the "allowed rate of return objective" is achieved. This objective is to be commensurate with the efficient financing costs of a benchmark efficient DNSP with a similar risk profile to Ergon Energy's[59].

6.2 Key policies and assumptions

Ergon Energy's ACS default metering asset base is contained in the SCS RAB category of metering, which also contains the asset base for network metering and the value of load control assets at customers' premises. Ergon Energy's policy is to allocate the metering RAB to ACS and SCS based on the estimated depreciated replacement cost of each of the asset sub-classes.

The value of the ACS default metering opening MAB was calculated using the Optimised Depreciation Replacement Cost (ODRC) method. This method calculates the current market value of an asset based on the gross replacement costs of a modern equivalent asset that has been optimised for a particular purpose and is then adjusted for depreciation to reflect the lifespan of the original asset.

[57] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 6.3 and 6.5
[58] Ibid, Clause 6.5.5 (b)
[59] Ibid, Clause 6.5.2 (c)

The proposed policy is to apply the ODRC method to value Ergon Energy's opening ACS default metering opening MAB for the following reasons:

1. The ODRC has previously been used to value electricity distribution assets when appropriate historical data was not available. For example, in 2003 the ODRC was proposed by Transend and approved by the Australian Competition and Consumer Commission as the method to value its opening RAB[60].

2. Most opening RAB values for electricity network assets were calculated using ODRC.

3. The ODRC method measures the minimum cost of replicating the system in the most efficient way possible, given its service requirements and the age of the existing assets[61].

The ODRC method generated an ACS default metering opening MAB value of $61.6m. The ODRC was estimated by multiplying the number of regulated Type 5 and 6 assets by their modern equivalent asset price, and reducing this value by depreciation assuming straight line depreciation and standard asset lifetimes. The key inputs used to generate the opening value of Ergon Energy's MAB using this method are detailed in Table 11 below.

Table 11: Key assumptions in ACS default metering opening MAB calculation

Inputs	Value	Units	Source
Weighted Average Asset Cost	$373	$/site	$339 per meter, assuming 1.1 meters per site in future
Customers	716,000	NMI	Ergon 2015/16 NMIs
Historical CPI Growth	5.58%	p.a.	ABS QLD average annual CPI for 1971-2013
Historical Household Growth	0.90%	p.a.	ABS QLD average annual population growth, 1971-2013
CPI x Household Growth	106.5%	p.a.	ABS sources above
Metering Asset Life	25	years	Ergon standard metering asset life
ACS default metering opening RAB	**$61.6**	**Million**	

Source: ABS and Ergon Energy MTPTRM.

[60] ACCC, Transend Networks Pty Ltd, Valuation of Transmission Assets, August 2003, page 3
[61] IPART, Regulation of NSW Electricity Distribution Networks, Determination and Rules under the National Electricity Code, December 1999, page xxi.

7. Other components of building blocks

This section details Ergon Energy's proposal for other components of its building blocks relevant to the development of its ACS default metering annual revenue requirements.

7.1 Depreciation

Ergon Energy retains the view that it presented in its 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.

If, however, the AER maintains its proposal not to 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 Rules than AER's proposed approach.

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 detailed justification for this proposal is set out in our accompanying document, *Submission to the AER on its Preliminary Determination Metering*.

Allowing Ergon Energy to recover its residual metering capital asset base over a five year period would enable it to recover its costs:

- Predominantly from the customer who benefited from the meters; and
- In a reasonable timeframe, whereby the affected customer can relate its 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 Rules. 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 AER proposed approach of recovering the costs over 15 years.

7.2 Weighted average cost of capital and gamma

Although ACS are prima facie riskier than SCS due to the exposure to competitive pressures and volume risk, Ergon Energy has adopted the same assumed Weighted Average Cost of Capital (WACC) and gamma for its proposal as those that it has applied for SCS.

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, Ergon Energy questions whether the AER intends to annually adjust for the return on debt as per the approach adopted for SCS.

7.3 Corporate tax rate

Ergon Energy has assumed a 30 per cent rate of corporate tax. This is the same assumption made in its SCS proposal.

7.4 Inflation

Ergon Energy has assumed the same forecast rate of inflation as that used in its SCS submission.

8. Revenue requirements

This section presents Ergon Energy's annual revenue requirements for its ACS default metering services derived from applying the AER's PTRM.

8.1 Regulatory requirements

Where the AER makes a determination on the basis of a building blocks approach, it must specify the annual revenue requirement. The manner in which Ergon Energy is to calculate its annual revenue requirement for each year of the regulatory control period is set out in the AER's PRTM.

The AER's PTRM utilises the "accrual building blocks" approach to revenue modelling. The following building blocks are summed in the model to determine the annual revenue requirement:

- Return on capital
- Return of capital (regulatory depreciation)
- Operating and maintenance expense
- Estimated taxation liability.

The principal inputs to the PTRM comprise the following:

- RAB and tax asset base, as determined by the RFM
- Forecast Capex
- Forecast Opex
- Financial parameters, including CPI and the elements of the WACC calculation.

8.2 Post Tax Revenue Model

Ergon Energy has used the building blocks approach to determine the forecast revenue requirements for ACS default metering services over the 2015-20 regulatory control period based on the proposed Opex, Capex and RAB inputs already discussed. A building block approach calculates the annual revenue requirements by summing up the return on capital, annual Opex requirements and other costs (such as tax and indirect overheads).

Ergon Energy's annual revenue requirements, as calculated using the AER's PTRM, are shown in Table 12. The model shows required revenue increasing from $53.26 million in 2015-6 to $84.77 million by 2019-20.

Table 12 – ACS default metering revenue requirement by Year ($m, Nominal)

	2015-16	2016-17	2017-18	2018-19	2019-20
Return on Capital	4.56	4.93	4.80	4.39	3.46
Return of Capital	11.06	17.88	22.17	28.63	29.89
O & M	34.79	37.30	39.79	41.87	44.01
Tax	2.84	4.24	5.76	7.38	7.42
Total Revenue Requirement	**53.26**	**64.35**	**72.52**	**82.27**	**84.77**

Source: Ergon Energy, MTPricing Model, Unconstrained meter pricing sheet.

9. Metering tariffs

This section outlines the tariffs Ergon Energy is proposing for its annual capital and non-capital metering services.

9.1 National Electricity Rules

There are no specific provisions in the NER governing ACS tariffs, nor did the AER provided specific guidance regarding metering ACS charges in its F&A paper.

Ergon Energy has therefore assumed that the AER will require ACS charges to comply with the same requirements as specified for SCS charges. The requirements for SCS charges are governed by the Distribution Pricing Rules, as set out in Clause 6.18 of the NER.

The Distribution Pricing Rules require that tariff classes group customers on an economically efficient basis, avoid unnecessary transaction costs[62] and that the revenue expected to be recovered by each tariff class lies on or between[63]:

- An upper bound representing the standalone cost of serving retail customers who belong to that class;
- A lower bound representing the avoidable cost of not serving those customers.

Further requirements under the Distribution Pricing Rules are set out in the "Regulatory requirements" section above.

9.2 Key policies and assumptions

Ergon Energy has based its proposed annual charges on the two components specified in the AER's Preliminary Determination:

- Capital charge – MAB recovery
- Non-capital charge – Opex and tax recovery

9.3 Unconstrained annual ACS default metering charges

Ergon Energy's proposed annual ACS default metering service charges have been set based on the required revenue each year, the cost allocation weighting between primary, controlled load and solar metering services, and the forecast number of services each year.

Table 13 shows the relative costs of primary, controlled load and solar and the proportion of ACS default metering revenue assigned to each tariff category. The relative costs are based on the net present value of forecast ACS default metering Capex and Opex, weighted by the cost allocation between primary, controlled and solar metering services.

[62] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 6.18.3 (d)
[63] Ibid, Clause 6.18.5 (a)

Table 13 – Proportion of ACS default revenue by tariff category for 2015-20

Tariff Category	Relative Cost	% allocation of revenue to tariff Category
Primary	100%	78%
Controlled Load	37%	18%
Solar	25%	4%

Source: Ergon Energy MTPricing Model.

Tables 14 and 15 present the annual revenue requirement and annual service charge and customer class for the 2015-20 regulatory control period. The total ACS default metering revenue requirement shown in Table 14 is the same as the total ACS default metering annual revenue requirement shown in Table 12 from the PTRM results.

Table 14 shows the volume of ACS default metering services for primary, controlled load and solar.

Table 14 – Annual ACS default metering revenue requirement ($m, Nominal)

	2015-16	2016-17	17-18	2018-19	2019-20
Primary	41.66	50.30	56.66	64.25	66.20
Controlled Load	9.76	11.64	12.95	14.50	14.76
Solar	1.83	2.41	2.91	3.51	3.81
Total ACS default metering revenue requirement	**53.26**	**64.35**	**72.52**	**82.27**	**84.77**

Source: Ergon Energy MTPricing Model.

The annual ACS default metering prices, shown in Table 15, are calculated by dividing the revenue requirements for primary, controlled load and solar services by the volume of services in each of these tariff categories. The Capital and non-capital components are calculated by the weighted forecast average of their respective costs in the Annual Revenue Requirement.

Table 15 – Unconstrained Annual ACS default metering charges ($ Nominal)

	2015-16	2016-17	2017-18	2018-19	2019-20
Primary Service	**58.47**	**69.22**	**76.47**	**85.06**	**85.98**
Non-Capital	37.25	44.10	48.72	54.19	54.78
Capital	21.22	25.12	27.75	30.87	31.20
Controlled load	**21.50**	**25.45**	**28.12**	**31.27**	**31.61**
Non-Capital	13.7	16.22	17.91	19.92	20.14
Capital	7.8	9.24	10.20	11.35	11.47
Solar	**14.54**	**17.21**	**19.02**	**21.15**	**21.38**
Non-Capital	9.26	10.97	12.11	13.47	13.62
Capital	5.28	6.25	6.90	7.68	7.76

Source: Ergon Energy MTPricing Model.

Ergon Energy is of the view that the proposed charges for annual ACS default metering services are consistent with the NER, being between the stand alone and avoidable cost of the service.

9.4 Constrained annual ACS default metering charges

The charges set out in Table 15 above are the charges that would apply if the Preliminary Determination did not come into effect from 1 July 2015 (i.e. the unconstrained prices).

However, as the Preliminary Determination applies from 1 July 2015, 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.

As Ergon Energy has taken an approach to default metering services that is largely consistent with SCS, we have applied a true-up mechanism to default metering services revenue through the use of X-factors. That is, X-factors are applied in order to smooth the ARR over the regulatory control period. This is normally achieved by making a Year 1 adjustment, and holding the smoothing adjustments in Years 2 to 5 at a constant rate (i.e. a constant 'X'). In Ergon Energy's case, the X-factors can only be adjusted for the remaining four years of the regulatory control period (2016-17 to 2019-20). This is because the prices for 2015-16 have already been established through the annual Pricing Proposal process based on the AER's Preliminary Determination. Therefore, Ergon Energy has made an adjustment in Year 2 and applied a constant X-factor over the remaining years of the regulatory control period. Our document entitled *Submission to the AER on its Preliminary Determination – Metering* provides further details.

Further, we note this approach is consistent with the AER's comments on the requirements for cost reflective pricing under the NER in Attachment 14 of its Preliminary Determination that deals with "Control Mechanisms".

Ergon Energy refers to these adjusted charges as "Constrained annual ACS default metering charges". These charges are set out in table 16.

However, Ergon Energy notes that there are many ways to apply a true-up mechanism and has presented this method to assist the AER. Ergon Energy would be pleased to work with the AER on the most appropriate mechanism as they prepare the Final Determination.

Table 16 – Constrained Annual ACS default metering charges ($ nominal)

	2015-16	2016-17	2017-18	2018-19	2019-20
Primary Service	**30.93**	**84.23**	**86.69**	**89.25**	**91.93**
Non-Capital	24.44	50.27	51.73	53.26	54.86
Capital	6.49	33.96	34.96	35.99	37.07
Controlled load	**11.38**	**30.97**	**31.87**	**32.82**	**33.80**
Non-Capital	8.99	18.48	19.02	19.58	20.17
Capital	2.39	12.49	12.85	13.23	13.63
Solar	**7.69**	**20.95**	**21.56**	**22.19**	**22.86**
Non-Capital	6.08	12.5	12.86	13.25	13.64
Capital	1.61	8.45	8.69	8.95	9.22

Source: Ergon Energy MTPricing Model.

10. Summary and conclusion

Ergon Energy's proposed ACS default metering charges have been developed in response to the AER's re-classification of Type 5-6 metering services from SCS to ACS in its F&A paper for Queensland DNSPs.

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:

- Updated asset replacement expenditure
- The 2013-14 base year for Opex
- Updated inputs including overhead rates, inflation, escalators, the Weighted Average Cost of Capital and gamma
- Capital and non-capital charges for recovery of the costs associated with the Default Metering Service

Ergon Energy's proposed annual capital charges recover its return on capital and depreciation attributable to its default metering services. These charges have been calculated based on $71.82 million (real $2014-15) for the next regulatory control period. This comprises $34.92 million for asset replacement, $10.54 million for customer initiated capital works (failed in service meter installations), $2.6 million in other Capex for field based meter configuration capability and $23.75 million in Capex overheads.

Ergon Energy's proposed annual non-capital charges recover its Opex and tax allowance attributable to its default metering services.

11. Compliance and supporting documentation

11.1 Compliance

Ergon Energy's ACS Default metering prices have been developed on a cost reflective basis, based on the key drivers of providing the metering service for each category. The proposed approach is therefore in compliance with the following clauses of the NER:

- Clause 6.18.3(d)(1) - Ergon Energy has developed tariff classes that group customers on an economically efficient basis in that they are based on the nature of the network connection.
- Clause 6.18.3(d)(2) - Ergon has developed metering tariff classes to avoid unnecessary transaction costs by limiting classes to materials categories.
- Clause 6.18.5(a) – The expected revenue to be recovered by each tariff category lies on or between the standalone and avoidable cost of serving those customers.

11.2 Supporting documentation

The following documents and models were used to support the development of Ergon Energy's ACS Default Metering Pricing proposal for 2015-20:

1. Ergon Energy, *00255 Engineering Report Meter Replacement Program*, 8 September 2014

2. Ergon Energy, *Meter Configuration Management System Report*, February 2014

3. Ergon Energy, *Cost Allocation Method*

4. Energeia, *ACS Metering Tariffs for 2015-20, Customer Council Working Group Meeting,* 18 June 2014

5. Ergon Energy, *Informing Our Plans, Our Engagement Program,* October 2014

6. Ergon Energy, *Metering Vision and Strategy,* October 2014

7. Huegin, *Ergon Energy Expenditure Benchmarking – Partial Productivity and Cost Driver Analysis and Comparisons,* October 2014, p3

8. Ergon Energy, Metering Post-Tax Revenue Model (PTRM)

9. Ergon Energy, ACS Meter Pricing Model

10. Ergon Energy, *Submission to the AER on its Preliminary Determination – Metering*

11. Ergon Energy, *Submission to the AER on its Preliminary Determination – Alternative Control Services – Other*