2015–16 Pricing Proposal

Distribution services for 1 July 2015 to 30 June 2016

Version 1.1 – AER approved

Revision history

Version	Date	Summary of changes
1.0	21 May 2015	Initial proposal to the AER for 2015–16.
1.1	27 May 2015	Minor amendments to sections 6.11 (Expected price trends), 6.12 (Designated pricing proposal charges incurred for TUOS), 8.2 (Adjustments to tariffs within a regulatory year), 8.3 (Changes between regulatory years). Approved by the AER on 12 June 2015.

Contents

1 Introduction

1.1 Background

Ergon Energy Corporation Limited (Ergon Energy) is a Distribution Network Service Provider (DNSP) to around 725,000 customers in regional Queensland. Our service area covers around 97 per cent of Queensland and has approximately 160,000 kilometres of power lines and one million power poles. Around 70 per cent of the network's power lines are radial and service mostly rural areas with very low levels of customers per line kilometre.

1.2 Purpose

Clause 6.18.2(a)(1) of the National Electricity Rules (NER) requires Ergon Energy to submit an initial Pricing Proposal (the 2015–16 Pricing Proposal) to the Australian Energy Regulator (AER) within 15 business days of the Distribution Determination. The AER's Distribution Determination for the regulatory control period 2015–20 was released on 30 April 2015.

The AER approves prices for services it classifies as Direct Control Services.[1] This Pricing Proposal assists the AER in approving these prices. It sets out how Ergon Energy's proposed tariffs and/or prices for Direct Control Services in 2015–16 meet the requirements of the NER.

Direct Control Services are separately classified into Standard and Alternative Control Services.[2]

Standard Control Services are core distribution services associated with the access and supply of electricity to customers. They include network services (e.g. construction, maintenance and repair of the network), some connection services (e.g. small customer connections) and Type 7 metering services. Ergon Energy recovers our costs in providing Standard Control Services through network tariffs billed to retailers.

Alternative Control Services are comprised of:

- *Fee based services* – regulated distribution activities Ergon Energy undertakes at the request of an identifiable customer, retailer or appropriate third party which are in addition to our Standard Control Services and are levied as a separate charge. These services are priced on a 'fixed fee' basis as the costs of providing the service (and therefore price) can be assessed in advance of the service being requested by a customer or retailer (e.g. de-energisations, re-energisations, and supply abolishment etc.).
- *Quoted services* – similar to fee based services, but they are 'priced on application' as the nature and scope of these services are variable and the costs (and therefore price) are specific to the individual retailer's or customer's needs (e.g. design and construction of connection assets for major customers, real estate development connections, special meter reads etc.).[3]
- *Default Metering Services* – relate to the provision, installation, maintenance, reading and data services of basic electricity meters (Type 5 and 6) for small to medium business and residential customers. These are the meters that measure the electricity that goes into a property, and which allow electricity retailers to bill their customers. Ergon Energy recovers our costs of providing Default Metering Services through charges based on the number and

[1] NER 6.1.3(b9)(2).
[2] Further details regarding the AER's decision on service classification can be found at Attachment 13 of its April 2015 Distribution Determination for Ergon Energy http://www.aer.gov.au/node/20186.
[3] The prices set out in this Pricing Proposal are examples of potential prices for quoted services.

type of meters we provide the customer. A separate upfront charge for new or upgraded meters is also payable.[4]

- *Public Lighting Services* – relate to the provision, construction and maintenance of public lighting assets owned by Ergon Energy, and emerging public lighting technology.
  Ergon Energy recovers our costs of providing Public Lighting Services through a daily public lighting charge billed to retailers. We also charge a one-off exit fee, which is payable when a public light is scrapped before the end of its useful operational life.[5]

The tariff schedules for our Standard Control Services are set out in Appendix 1 and Appendix 2, and, for our Alternative Control Services, in Appendix 4.

1.3 Structure

This Pricing Proposal is structured as follows:

- Part 1 provides an overview of Ergon Energy's pricing arrangements and approach to setting network prices for both Standard Control Services and Alternative Control Services. It includes:
  - an overview of the context in which we develop prices, including the relationship with the regulatory framework and our ongoing consultation process with customers on tariff reform
  - an explanation of the revenues we are required to recover through prices in 2015–16 for Standard Control Services
  - our approach to establishing the prices we are required to charge for Alternative Control Services.
- Part 2 details how this Pricing Proposal satisfies the requirements of the NER and the AER's Distribution Determination (hereafter referred to as the 'Preliminary Determination').

A series of appendices provide further information on our revenue and price calculations, including models and expected price trends.

In accordance with the AER's Confidentiality Guideline, Ergon Energy has provided both public and confidential versions of our Pricing Proposal, where required. Our confidentiality claims, including the proportion of confidential material contained within our Pricing Proposal and its attachments and appendices, are set out in Attachment 1. All confidential information in the public version has been redacted.

1.4 Use of terms

Unless otherwise specified, a reference to network tariffs refers to tariffs and tariff classes for Standard Control Services.

Where a section of this document applies to both customers and Embedded Generators (EGs) the term "network user" is used. Where the term "customer" is used in a section of this document, that section applies to customers only (i.e. it does not apply to EGs).

Where the term "TUOS" is used in a section of this document, it includes all designated pricing proposal charges incurred for Transmission Use of System (TUOS) services.

[4] The implementation of upfront metering charges is subject to discussion between Ergon Energy and the AER to be agreed before 1 July 2015.
[5] Outside of our light emitting diode (LED) transition program.

1.5 Supporting network pricing documents

In addition to this Pricing Proposal, Ergon Energy has a number of network pricing documents to assist customers, retailers and interested parties understand the development and application of tariffs and connection charges. The documents outlined in Figure 1.1 below provide further information about network tariffs, including tariff assignment, Network Tariff Codes, loss factors and detailed information about operational issues relating to Standard and Alternative Control Services.[6]

The *Network Tariff Guide* and the *Price List for Alternative Control Services* will also set out the tariffs and prices for 2015–16 and any other changes that are required as a result of this Pricing Proposal, once approved.

Figure 1.1: Supporting network pricing documentation

Information Guide for Standard Control Services Pricing	• Sets out the basis upon which Ergon Energy's revenue cap for Standard Control Services is recovered from various customer groups through network tariffs • Provides a description of the network tariffs • Provides details on the assignment of customers to tariff classes and network tariffs • Published annually
Network Tariff Guide	• An operational document for customers, retailers and consultants, setting out the Network Tariff Codes, as well as application rules and rates for each Network Tariff Code • Applies to network users connected to Ergon Energy's regulated distribution network • Published annually, and updated as required
Information Guide for Alternative Control Services Pricing	• Sets out the basis upon which Alternative Control Services pricing is set and approved by the AER • Provides details on the assignment of customers to tariff classes • Published annually
Price List for Alternative Control Services	• Sets out Ergon Energy's Alternative Control Services and the prices that apply for fee based services, Default Metering Services and Public Lighting Services • Published annually, and updated as required
Connection Policy	• Sets out when a connection charge may be payable by retail customers or real estate developers and the aspects of the connection service for which a charge may be applied • Details how Ergon Energy calculates the capital contribution to be paid • This policy was approved by the AER in April 2015 at the time of the Distribution Determination

6 These documents will be available on Ergon Energy's website at: www.ergon.com.au/networktariffs.

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PART 1 – APPROACH TO PRICE SETTING

2 Matters impacting Ergon Energy's revenue and network prices for 2015–20

2.1 Regulatory framework

As a DNSP, Ergon Energy is subject to economic regulation by the AER under the National Electricity Law (the Law) and the NER. Under the Law and NER, the AER is responsible for regulating the revenues Ergon Energy can earn, and the prices that Ergon Energy can charge for certain services provided by means of, or in connection with, our distribution system.

2.1.1 Preliminary Determination

On 30 April 2015, the AER made its Preliminary Determination for regulated distribution services provided by Ergon Energy. The Preliminary Determination effectively sets the revenue and pricing control regime that Ergon Energy must comply with in 2015–16 for these services. It also details jurisdictional scheme arrangements relating to the Queensland Government Solar Bonus Scheme.

2.1.2 Substitute Determination

Under transitional arrangements, the Preliminary Determination will be revoked and substituted (the Substitute Determination) by 31 October 2015.[7] Although the Substitute Determination will not be made until after the commencement of the regulatory control period 2015–20, it will be applied as from 1 July 2015, with a 'true-up' applied to account for changes between the Preliminary Determination and the Substitute Determination.

These 'true-up' adjustments include:

- for Standard Control Services, increasing or decreasing the Annual Revenue Requirement (ARR) set out in the Post Tax Revenue Model (PTRM) for one or more remaining regulatory years of the regulatory control period 2015–20 by an adjustment amount. This amount is calculated as:
  - the amount of the ARR that was approved by the AER for the first regulatory year of the regulatory control period in the Preliminary Determination, less
  - the amount of the ARR for the first regulatory year of the regulatory control period that is determined in the Substitute Determination[8]
- for Alternative Control Services, making adjustments to accommodate any difference between revenues or prices that are approved under the Preliminary Determination for the first regulatory year of the regulatory control period and revenues or prices that are approved under the Substitute Determination for that first regulatory year. This may include making adjustments to any existing or future approved pricing proposals.

Further information on the true-up adjustments will be known once the Substitute Determination is released.

2.2 Network Tariff Strategy

There has been a major shift in the way our customers use the electricity network in recent years. Strong economic growth in the early 2000s, coupled with a drop in the price of electrical appliances (including air conditioning), led to a dramatic increase in demand for electricity during peak usage

7 NER, clause 11.60.4(c).
8 NER, clause 11.60.4(e).

periods. In more recent times, while peak demand has remained high, the economic slowdown, the growing use of solar energy and the focus on energy efficiency (as retail electricity prices have risen) has led to a drop in electricity use overall.

This means our network, which we invested in heavily to respond to the growth in demand during peak times (which can occur for only a few days a year), is now not being used as effectively as it could be outside peak times.

Ergon Energy is therefore restructuring the way we charge for the use of our distribution network to help ensure we maintain a viable network for our customers into the future. This process is expected to take a number of years, with the first changes implemented in 2014–15.

In developing our network tariff changes, we have consulted with a wide range of our customers and our stakeholders over the past two years. The resulting short, medium and longer term tariff development intentions have been available and progressively updated on our website since June 2013,[9] and have been subject to multiple rounds of public consultation.

The tariff structures are designed to allow our customers, through their retail account, to better understand the cost associated with accessing the network and the time they use electricity. This is particularly important when customers are making decisions around any future investment and use of new energy-related technologies, such as on-site generation, batteries and storage, electric vehicles, home automation, and other emergent innovations.

In broad terms, Ergon Energy proposes to make the following changes to network tariff structures in 2015–16:

- introduce an excess reactive power charge (excess kVAr) for our largest customers (energy consumption greater than 40 GWh per annum (p.a.))
- introduce an optional Seasonal Time-of-Use Demand (STOUD) tariff to all customers with energy consumption less than 40 GWh p.a.
- extend kVA as the basis for the demand tariffs to all very large energy users (energy consumption greater than 4 GWh p.a.)
- reduce the number of customer specific tariffs by introducing standard tariff rates for Connection Asset Customers
- commence phasing out the high voltage tariffs for our large customers (energy consumption between 100 MWh p.a. and 4 GWh p.a.).

Further information on the 2015–16 changes is set out in Section 8.3. These changes have been incorporated in the structures and tariffs submitted in this Pricing Proposal.

It should be noted that Ergon Energy's network tariff development pathway is being deployed in an increasingly dynamic industry, regulatory and market environment. With fundamental regional Queensland market changes possible in the short to medium term, and uncertainty around the level of market and customer response to the new tariffs, a tariff development pathway that is responsive to these changes is required.

While the fundamental themes, underlying drivers and future pathway of the network tariff strategy development are not expected to change, the actual rate and depth of deployment may. Our intention is to continue to consult with our customers and stakeholders, and maintain transparency of our network tariff development plans. It is important to note that as market reforms increasingly impact on the electricity supply industry, Ergon Energy's network tariff structures will evolve on a continuous basis.

[9] www.ergon.com.au/futurenetworktariffs.

3 Establishing 2015–16 tariffs for Standard Control Services

3.1 Overview

Ergon Energy's Standard Control Services are regulated under a revenue cap form of price control. The revenue cap for any given year reflects Ergon Energy's smoothed revenue requirement, as determined by the AER's PTRM, plus adjustments relating to:

- inflation
- return on debt[10]
- incentive schemes
- under or over-recoveries in actual revenue like amounts relating to the clearing of the Distribution Use of System (DUOS) unders and overs account
- other factors such as amounts associated with the occurrence of any prescribed and nominated pass through events.

The resulting revenue cap outlined in Section 3.2 below is then recovered from various customer groups through network tariffs in accordance with our network tariff development process summarised in Section 3.3.

Designated pricing proposal charges (or TUOS) and jurisdictional scheme amounts relating to feed-in tariff (FiT) payments made under the Solar Bonus Scheme are then allocated to customers (refer to Sections 3.4 and 3.5, respectively).

3.2 Revenue recovery in 2015–16

In 2015–16, the total network (transmission, distribution and jurisdictional scheme) revenue that Ergon Energy will need to recover from network users is approximately $1,919 million.

The amount to be recovered includes Ergon Energy's revenue cap of approximately $1,444 million. This is 21.44 per cent below what we expected to recover from network users in 2014–15. This reflects adjustments made to Ergon Energy's 2015–16 smoothed revenue requirement set out in the PTRM for:

- the Service Target Performance Incentive Scheme (STPIS)
- the difference between forecast and actual capital contributions relating to 2013–14
- unders and overs adjustments for shared assets relating to 2013–14
- the pass through amount associated with FiT payments made under the Solar Bonus Scheme in 2013–14
- unders and overs associated with the DUOS unders and overs account.

A detailed discussion on the calculation of the revenue cap is contained in Section 6.5 of this Pricing Proposal.

[10] Under the trailing average portfolio approach, the rate of return on debt, and consequently the allowed rate of return, will vary each regulatory year. As such, the PTRM and the smoothed revenue requirement are amended each year to take into account the updated allowed rate of return. This is not the case in 2015–16 as the smoothed revenue requirement published in the Preliminary Determination already incorporates the 2015–16 allowed rate of return.

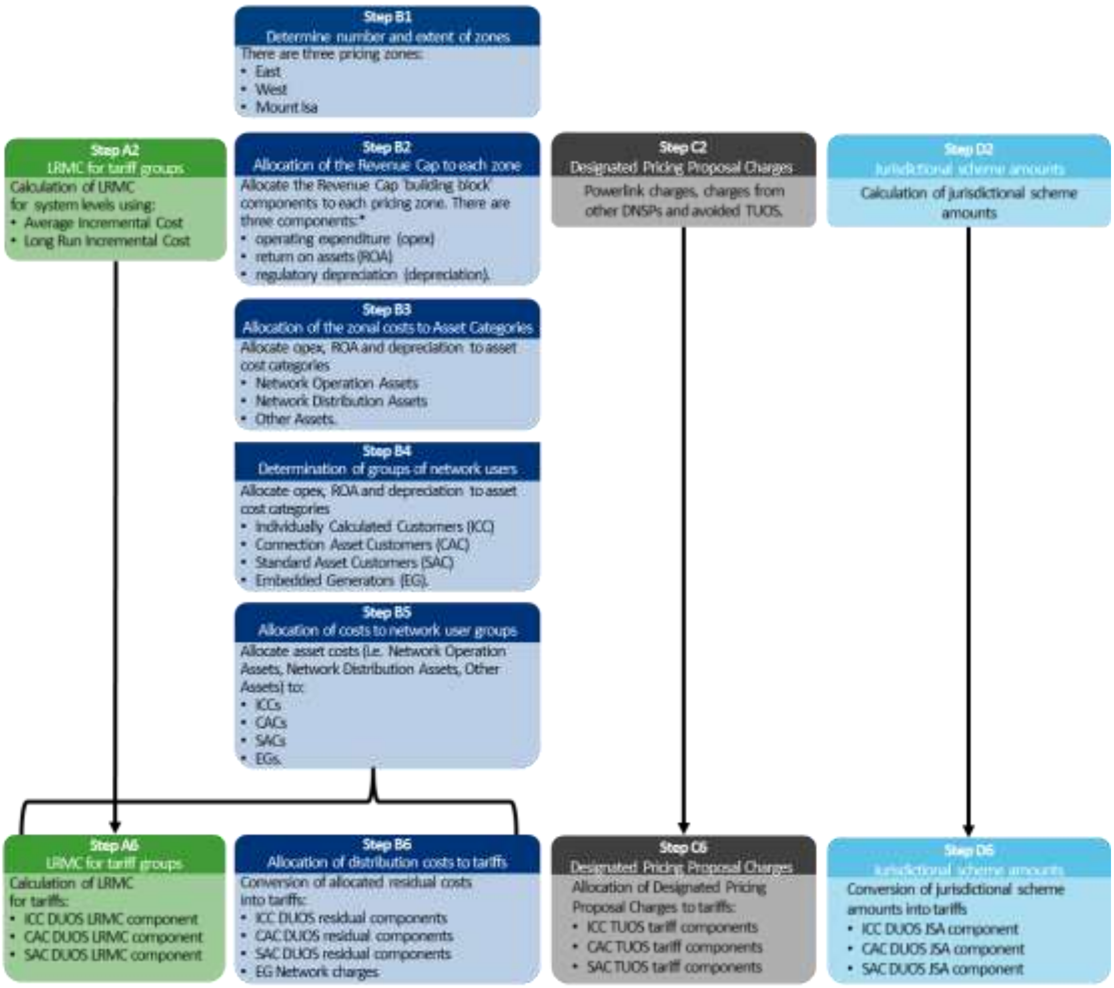
Ergon Energy also recovers revenues on behalf of Powerlink and other designated pricing proposal charges (approximately $361 million) as outlined in Section 3.4, and jurisdictional scheme revenue associated with the Solar Bonus Scheme (approximately $114 million) as outlined in Section 3.5.

3.3 Development of network tariffs for Standard Control Services

The process for allocating and converting the revenue cap to network tariffs for the various customer groups is set out in Figure 3.1 below. Essentially, the revenue cap is allocated to the three pricing zones and the zonal costs are apportioned to different asset categories within each zone. The costs within the zones are then assigned to the four network user groups and converted into network tariffs that recover the costs. As noted above, TUOS and jurisdictional scheme amounts are then allocated to customers.

The following sections provide high level information on the pricing zones and the network user groups, as well as the Major Customer Connection arrangements which may apply to certain network users. Further information can be found in the *Information Guide for Standard Control Services Pricing*.

Figure 3.1: Network tariff development



* Ergon Energy's smoothed revenue requirement (prior to annual revenue adjustments) is determined by the AER using the accrual building block approach. The building block components comprise allowances for ROA, regulatory depreciation (depreciation), opex, revenue adjustments and a tax allowance. For pricing purposes, revenue associated with the tax allowance and other revenue adjustments (included in the building blocks or calculated in the revenue cap formula) is pro-rated across the ROA, depreciation and opex building block components.

3.3.1 Network user groups

Ergon Energy currently has four network user groups (with multiple tariff classes within these groups). These are:

- Individually Calculated Customers (ICCs)
- Connection Asset Customers (CACs)
- Standard Asset Customers (SACs)[11]
- Embedded Generators (EGs).[12]

A description of the four network user groups is provided in Table 3.1 below.

The purpose of these network user groups is to enable network tariffs to be developed that provide individual or direct cost of supply signals to those network users where possible, while recognising that it is not possible to price every network user individually.

Table 3.1: Ergon Energy's network user groups

Network user group	Description

ICC	Those customers:
	▪ with energy consumption typically greater than 40 GWh p.a., or
	▪ with energy consumption lower than 40 GWh p.a. where:
	  o a customer has a dedicated supply system which is quite different and separate from the remainder of the supply network
	  o there are only two or three customers in a supply system making average prices inappropriate
	  o a customer is connected at or close to a Transmission Connection Point, or
	  o inequitable treatment of otherwise comparable customers will arise from the application of the 40 GWh p.a. threshold.

CAC	Those customers:
	▪ with required capacity above 1,500 kVA
	▪ with energy consumption typically greater than 4 GWh p.a., or
	▪ with required capacity below 1,500 kVA where:
	  o a customer has a dedicated supply system which is quite different and separate from the remainder of the supply network, or
	  o inequitable treatment of otherwise comparable customers will arise from the application of the 4 GWh p.a. threshold.
	The CAC group is further subdivided into categories based on voltage levels as follows:
	▪ 66 kV – connected to either a 66 kV substation or a 66 kV line
	▪ 33 kV – connected to either a 33 kV substation or a 33 kV line
	▪ 22/11 kV Bus – connected to either a 22 kV or 11 kV substation
	▪ 22/11 kV Line – connected to either a 22 kV or 11 kV line.

SAC	All other load customers. This includes customers with micro generation facilities (such as small scale photovoltaic (PV) generators) that have exporting capability and an inverter capacity as per Australian Standard (AS) 4777. The SAC group is further subdivided into network tariff categories based on whether: ▪ the customer's connection is metered or unmetered ▪ the customer's consumption relates to residential or business use ▪ the customer is taking supply at high voltage or low voltage ▪ the customer's consumption is above or below 100 MWh p.a. ▪ the customer has a meter installed capable of recording demand

[11] Unmetered loads such as public lights are treated as a SAC.

[12] EGs may also take load from the system. The load side will be classified as an ICC, CAC, or SAC, and a separate network tariff will apply.

Network user group	Description
	▪ the customer's supply is capable of being controlled by Ergon Energy.
EG	Those network users that export energy into the distribution system. EGs do not include micro embedded generators as defined under AS4777. EGs are separated into two categories: ▪ EGs that are connected to the distribution system and only generate into the distribution system ▪ EGs that are connected to the distribution system, generate and take load from the system.

3.3.2 Pricing zones

Network pricing zones are utilised by Ergon Energy to define geographic areas of the network where costs are assessed to be broadly similar. Ergon Energy has three pricing zones:[13]

- **East Zone** – those areas where the network users are supplied from the distribution system connected to the national grid and have a relatively low distribution cost to supply
- **West Zone** – those areas outside the East Zone and connected to the national grid, which have a significantly higher distribution cost to supply than the East Zone
- **Mount Isa Zone** – broadly defined as those areas supplied from the isolated Mount Isa system. This zone is not connected to the national grid and, as such, would normally be excluded from the application of the NER. However, under the *Electricity – National Scheme (Queensland) Act 1997*, the Queensland Government has transferred responsibility for the economic regulation of the Mount Isa–Cloncurry supply network to the AER.

The local government areas covered by each zone and a map depicting each zone are located in the *Information Guide for Standard Control Services*.

3.3.3 Major Customer Connection arrangements

Since 2010 network tariffs for major customers have been differentiated by whether the customer was connected under legacy arrangements where connection assets were included in the network tariff or the Major Customer Connection arrangements introduced on 1 July 2010 where new or augmented connection assets were paid for or contributed by the customer.

ICCs, CACs and EGs connected under the Alternative Control Services Major Customer Connection arrangements were only able to access post 30 June 2010 network tariffs. Post 30 June 2010 network tariffs differed from those that applied to all other ICCs, CACs and EGs in that they no longer recovered the cost of new or augmented dedicated connection assets.[14] Dedicated connection assets for post 30 June 2010 ICCs, CACs and EGs were levied as an up-front payment, or were constructed by customers and gifted to Ergon Energy.

In 2015–16, Ergon Energy will consolidate the different tariff classes for pre and post 30 June 2010 connection dates. This consolidation does not impact individual customer tariff outcomes as each legacy customer will still receive an individual charge to reflect the connection assets included in their network tariff.

[13] Areas supplied from isolated (remote) generation are not included in any of the below zones.
[14] These network users will still pay operating and maintenance costs on their connection assets through their applicable network tariff.

3.4 Allocation of designated pricing proposal charges

Under the NER, Ergon Energy is able to recover designated pricing proposal charges incurred by Ergon Energy for TUOS services which include:

- charges for prescribed exit services, prescribed common transmission services and prescribed TUOS services. These charges are billed to Ergon Energy by Powerlink, the Queensland Transmission Network Service Provider (TNSP)
- avoided customer TUOS charges
- charges for distribution services provided by another DNSP.

Attachment 14 of the Preliminary Determination also allows us to pass through:

- charges levied on Ergon Energy for use of the 220 kV network which supplies the Cloncurry network
- entry and exit services charged by Powerlink at three connection points – Stoney Creek, Kings Creek and Oakey Town.

This means Ergon Energy must design tariffs to pass through costs related to the payment of TUOS to Powerlink, Avoided TUOS payments to eligible EGs and payments to other DNSPs for the use of their network. For simplicity, all designated pricing proposal charges incurred by Ergon Energy will be referred to as TUOS for the purposes of this Pricing Proposal.

The allocation of TUOS charges to customers in the formation of tariffs is undertaken on the basis described in Section 6.12.

3.5 Allocation of jurisdictional scheme amounts

Jurisdictional schemes are certain programs implemented by state governments that place legislative obligations on DNSPs. Jurisdictional schemes comprise:

- schemes set out explicitly under clause 6.18.7A(e) of the NER. For Queensland, this includes the Solar Bonus Scheme, which obligates Ergon Energy to pay a FiT for energy supplied into our distribution network from specific micro-embedded generators[15]
- those schemes determined by the AER to be jurisdictional schemes under clause 6.18.7A(l) of the NER. At the time of publishing this Pricing Proposal, there are no jurisdictional schemes captured by this clause in 2015–16.[16]

Our Pricing Proposal must set out how jurisdictional scheme amounts (i.e. the amount(s) we are obligated to pay under the scheme) for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those amounts.[17]

The allocation of jurisdictional scheme amounts in the formation of tariffs is undertaken on the basis described in Section 6.13.

3.6 Tariff schedules

Appendix 1 and Appendix 2 set out the tariffs that comprise each Standard Control Service tariff class and the relevant charging parameters.

[15] The scheme operates under clause 44A of the *Electricity Act 1994 (Qld).*

[16] Ergon Energy notes the Queensland Retailer of Last Resort scheme, which is currently considered to be a jurisdictional scheme, will cease to apply on 1 July 2015 following the introduction of the National Energy Customer Framework in Queensland.

[17] NER, clause 6.18.2(b)(6A).

4 Establishing 2015–16 tariffs for Alternative Control Services

4.1 Overview

Ergon Energy's Alternative Control Services are regulated under a price cap control mechanism. This means the AER determines Ergon Energy's efficient costs, and approves a maximum price that Ergon Energy can charge for the service.

Ergon Energy has established tariffs for Alternative Control Services consistent with the Preliminary Determination. That is, for:

- fee based and quoted services, a formula based approach is used to determine the efficient costs (and price) of providing the service (refer to Section 4.2)
- Default Metering Services, we have applied the regulated annual charges and upfront charges for new and upgraded meters consistent with what was determined by the AER (refer to Section 4.3)
- Public Lighting Services, we have applied the public lighting charges and exit fees consistent with what was determined by the AER. Prices are based on the type of public light (Major or Minor) and ownership status (refer to Section 4.4).

4.2 Tariff setting process for fee based and quoted services

4.2.1 Fee based services

Consistent with the Preliminary Determination, Ergon Energy has applied the following cost build up formula to calculate the initial prices to be levied for our fee based services in 2015–16:

$$\boldsymbol{Price = Labour\ + Contractor\ Services\ + Materials + Capital\ Allowance}$$

Where:

Labour consists of all labour costs directly incurred in the provision of the service which may include labour on costs, fleet on costs and overheads

Contractor Services reflect all costs associated with the use of external labour, including overheads and any direct costs incurred as part of performing the service. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred are passed on to the customer

Materials reflect the cost of materials directly incurred in the provision of the service, material storage and logistics on costs and overheads

Capital Allowance represents a return on and return of capital for non-system assets.[18]

We have updated various inputs since the release of the Preliminary Determination. These changes are discussed in Section 7.3.1. The calculation of Ergon Energy's fee based services prices is set out in Appendix 5.

[18] Excluding vehicle depreciation, as this is included in the fleet on cost.

4.2.2 Quoted price services

In accordance with section 16.1.1 of Attachment 16 of the Preliminary Determination, Ergon Energy will apply the cost build up formula outlined in Section 4.2.1 above when calculating tariffs to be levied for our quoted services.

We have updated various inputs since the release of the Preliminary Determination. These changes are discussed in Section 7.3.1. The calculation of Ergon Energy's illustrative quoted services is set out in Appendix 5.

4.3 Tariff setting process for Default Metering Services

4.3.1 Types of ACS metering services

Ergon Energy provides two types of Alternative Control Services in relation to metering services:

- Auxiliary Metering Services, which are non-routine metering services that Ergon Energy provides on request (e.g. special meter reads)
- Default Metering Services.

Auxiliary Metering Services are priced on a quoted basis. This means the costs to Ergon Energy in undertaking this work are recovered through separate upfront charges levied on those who utilise the particular service. Tariffs for this service group are calculated on a price on application basis in accordance with the cost build up formula for quoted services set out in Section 4.2.1 of this Pricing Proposal.

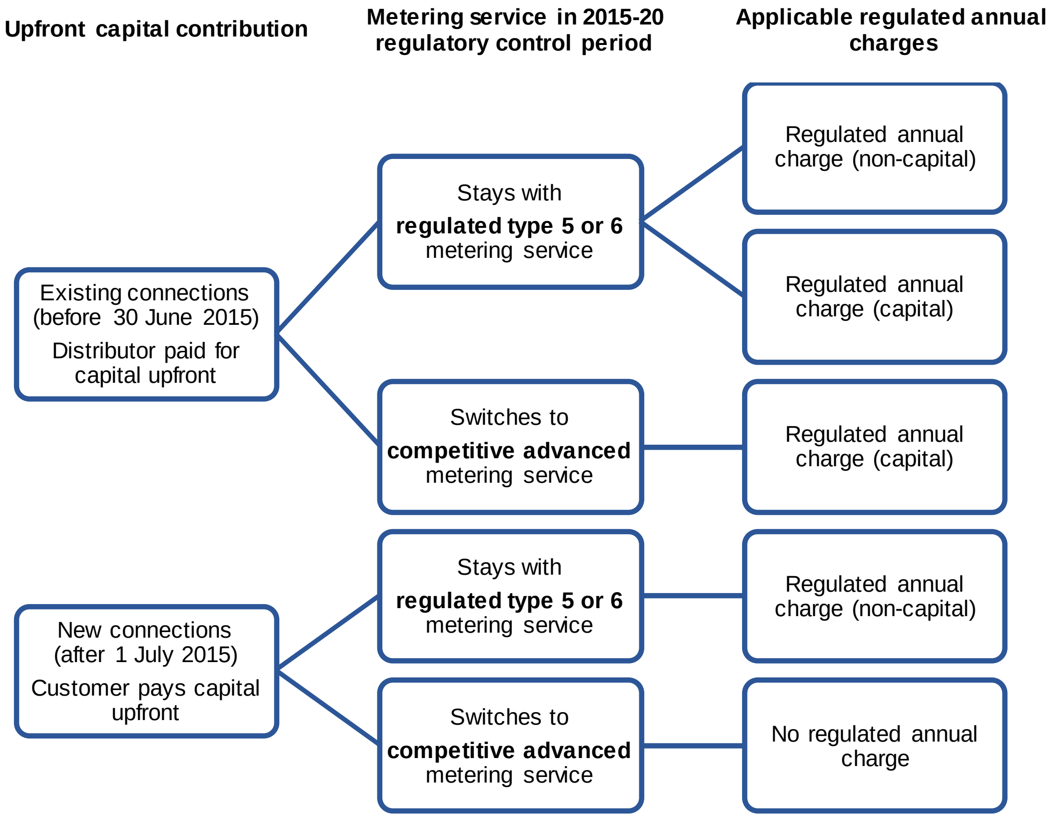
The AER's preliminary decision for Default Metering Services approves two types of metering service charges:[19]

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

The type of regulated annual charges that apply to metering customers will differ, depending on the customer's circumstances. The following diagram illustrates, at a high level, when the applicable regulated annual charges will apply.

[19] AER (2015), *Preliminary Decision, Ergon Energy Determination 2015–16 to 2019–20, Attachment 16 – Alternative Control Services*, April 2015, p20.

Figure 4.1: Regulated annual charges



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

4.3.2 Calculating Default Metering Services tariffs

Regulated annual charges

Our Default Metering Services 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. The revenue for the capital and non-capital annual charges has been determined using a limited building block approach, which includes the return on capital, return of capital (regulatory depreciation), opex and tax allowance for all Type 5 and 6 meters installed up to 30 June 2015, and opex and tax allowance for new meters expected to be installed after 30 June 2015.

For 2015–16, we have applied the regulated annual charges set out in Appendix A.2 of Attachment 16 of the Preliminary Determination. These charges are provided in Appendix 4.

Upfront charge

In accordance with Attachment 16 of the Preliminary Determination, Ergon Energy has applied the following price cap formula to calculate the upfront charges for 2015–16:

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

Where:

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

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

ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics (ABS) Consumer Price Index (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 the factors set out in Table 16.7 of the Preliminary Determination.

The calculation of Ergon Energy's upfront charges, in accordance with this formula, is set out in Appendix 5. The resulting upfront charges for single phase, dual element and three phase meters are provided in Appendix 4.

4.4 Tariff setting process for Public Lighting Services

4.4.1 Types of ACS public lighting services

Ergon Energy provides two types of Alternative Control Services in connection with public lighting infrastructure:

- provision, construction and maintenance of public lighting assets and emerging public lighting technology ('Public Lighting Services')
- removal/rearrangement of existing public lighting assets.

The removal/rearrangement of existing public lighting assets is a quoted service. This means the costs to Ergon Energy in undertaking this work are not recovered through the daily public lighting charge, but are instead recovered through separate upfront charges levied on those who utilise the service. Tariffs for this service are calculated on a price on application basis in accordance with the formula for quoted services set out in Section 4.2.1 of this Pricing Proposal.

Revenue for Public Lighting Services has been developed using a limited building block approach which includes the ROA, depreciation, opex and tax allowance for all public lights installed up to 30 June 2015, and new public lights forecast to be installed by or gifted to Ergon Energy after 30 June 2015.

Based on the approved ARR for Public Lighting Services, Ergon Energy calculated a daily charge ($/light/day) for Major and Minor public lights based on their ownership status. That is, whether the public light is:

- Ergon Energy Owned and Operated (EO&O)
- Gifted and Ergon Energy Operated (G&EO).

Public lighting infrastructure owned and maintained by Ergon Energy can be further classified between Major and Minor on the following basis:

- Major public lights – Ergon Energy's standard major public lights are 100, 150, 250 watt and some 400 watt High Pressure Sodium vapour lights. Major public lights also include any other non-standard or obsolete public lights that would be replaced with any of the above Ergon Energy standard major public lights in accordance with Ergon Energy policy.
- Minor public lights – Ergon Energy standard minor public lights are 50, 80 and 125 watt Mercury Vapour and some 70 and 100 watt High Pressure Sodium vapour lights (special locations only). Minor public lights also include any other non-standard or obsolete public lights that would be replaced with any of the above Ergon Energy standard minor public lights in accordance with Ergon Energy policy.

We have also established an exit fee for Major and Minor public lights based on their ownership status.

4.4.2 Calculating Public Lighting Services tariffs

Use of system charge

For 2015–16, we have applied the public lighting charges set out in Table 16.9 of Attachment 16 of the Preliminary Determination. These charges are set out in Appendix 4.

If Ergon Energy is requested by a customer to construct non-standard public lights, Ergon Energy may require the customer to pay an additional up-front amount towards the cost of the public light asset. Non-standard public lighting assets in this context are those where the cost of the service is not fully recovered through the daily public lighting charge over a 20 year term. The 20 year term represents a reasonable expectation of the average life of a public light asset.

The amount payable will be the incremental cost difference between a standard and non-standard public light calculated in accordance with AER requirements. Ergon Energy calculates the incremental cost as the shortfall between:

- the present value of expected revenue to be paid by the customer for Public Lighting Services over the life of a standard public light asset. This revenue is calculated using the relevant public lighting charge, and
- the estimated cost of providing the non-standard public lighting asset. These costs are calculated in accordance with the formula for quoted services set out in Section 4.2.1.

Exit fee

For 2015–16, we have applied the exit fees proposed in our Regulatory Proposal. These exit fees were approved by the AER in its Preliminary Determination.[20] However, we have updated for CPI (refer to Appendix 5). The exit fees applying in 2015–16 are set out in Appendix 4. It is important to note the exit fees do not apply to public lights that are scrapped as part of the LED transition program.

4.5 Tariff schedules

Appendix 4 sets out the 2015–16 tariffs for our Alternative Control Services. Specifically, it sets out the prices for our fee based services, Default Metering Services and Public Lighting Services, and examples of potential prices for quoted services for 2015–16.

In relation to each quoted service, it is important to note that the prices provided in Appendix 4 are examples only. This is because the actual prices for quoted services will be determined at the time of the customer’s enquiry and will reflect the actual requirements of the service.

4.6 Queensland Government caps on services

The Queensland Government has historically set maximum price caps to apply to a subset of Ergon Energy’s services through Schedule 8 of the *Electricity Regulation 2006*. Since the price caps are imposed through legislation, they take precedence over the prices approved by the AER. This means Ergon Energy cannot recover our full costs of providing these services and the shortfall is borne by us.

[20] AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 16 – Alternative control services*, April 2015, p57.

It is important to note that the prices contained in Appendix 4 reflect the tariffs derived under the tariff setting process and, depending on the type of service, the prices in Appendix 4 may be higher than the prices customers will be charged. The *Price List for Alternative Control Services* will provide the rates applicable for 2015–16 as a result of Schedule 8 maximum price caps, and hence the prices customers will be charged.

PART 2 – DEMONSTRATING COMPLIANCE

5 Overview of regulatory obligations

The matters that must be satisfied by the publication of this Pricing Proposal are outlined in section 6.18 of the NER. This includes a requirement on Ergon Energy to demonstrate compliance with the NER and any applicable Distribution Determination.[21]

Ergon Energy's compliance with the requirements is set out in the following chapters. For ease of reference, a summary of the obligations is also provided in Table 5.1 and Table 5.2.

Table 5.1: Compliance obligations under the NER

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
6.18.2(b)(1)	Set out each tariff class (including the classes of Alternative Control Services).	Tariff classes are set out and justified in Sections 6.1 and 7.1. The number of tariff classes for Standard Control Services has been reduced in 2015–16, following the removal of the pre and post 30 June 2010 distinction for major customers. These changes are discussed in Section 8.3.3. There have also been changes to the tariff classes for Alternative Control Services due to the classification of service changes detailed in the Preliminary Determination (refer to Section 8.3.1).
6.18.2(b)(2)	Set out the proposed tariffs for each tariff class.	Tariff schedules for Standard Control Services are set out in Appendix 1 and Appendix 2. These tariffs reflect the changes proposed to each of our network user groups, which are set out in Table 8.2. Tariff schedules for Alternative Control Services are provided in Appendix 4. There are a number of new services in 2015–16 following changes to the classification of services for the regulatory control period 2015–20. Refer to Section 8.3.1 for a summary of these changes.
6.18.2(b)(3)	Set out the charging parameters and the elements of service to which each charging parameter relates.	For Standard Control Services, details of the charging parameters and the elements of the service to which each relates are set out in Section 6.3. In 2015–16, Ergon Energy has introduced a new excess kVAr charge for our ICCs. More information on this charge is contained in Section 8.3.2. For Alternative Control Services, the charging parameters are fixed by the control mechanism imposed by the AER as outlined in Chapter 4.
6.18.2(b)(4)	Set out the expected weighted average revenue for each tariff class related to Standard Control Services.	Weighted average revenue calculations for each Standard Control Service tariff class are set out in Appendix 3. The reduction in tariff classes has been reflected in this table.
6.18.2(b)(5)	Set out the nature of any variation or adjustment to the tariff that could occur during the course of the regulatory year and the basis on which it could occur.	Variations and adjustments which could apply to tariffs during 2015–16 are set out in Section 8.2.

[21] NER, clause 6.18.2(b)(7).

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
6.18.2(b)(6) and 6.18.7	Set out how designated pricing proposal charges incurred by distributors for TUOS services are to be passed through to customers and any adjustments to tariffs resulting from over or under-recovery of those charges in the previous regulatory year.	The method of passing through designated pricing proposal charges (TUOS) to customers is generally addressed in Section 6.12. The approach to TUOS for our CACs has changed since 2014–15 as a result of the standardisation process. The approach taken is similar to that for SACs, with charges for each bulk supply point allocated to one of three geographical regions and charges being calculated on an aggregated regional basis.
6.18.2(b)(6A)	Set out how jurisdictional scheme amounts for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from the over or under recovery of those amounts.	The method of passing through jurisdictional scheme amounts to customers is generally addressed in Section 6.13.
6.18.2(b)(6B)	Describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria.	While there have been changes to aspects of the Solar Bonus Scheme since 1 July 2010, the scheme remains a jurisdictional scheme. Section 6.13.1 provides further details.
6.18.2(b)(7)	Demonstrate compliance with the NER and any applicable distribution determination.	This table and Table 5.2 demonstrate how Ergon Energy complies with the NER and our Preliminary Determination.
6.18.2(b)(8)	Describe the nature and extent of change from the previous regulatory year and demonstrate that the changes comply with the NER and any applicable Distribution Determination.	There have been a number of changes to pricing arrangements as a result of the Preliminary Determination. These changes are set out in Section 8.3.1. As noted in Section 2.2, Ergon Energy is also proposing a number of changes to our network tariff structures from 1 July 2015 for our Standard Control Services. Variations and adjustments incorporated into this year's Pricing Proposal as a result of these changes are set out in Sections 8.3.2 and 8.3.3. How these changes comply with the NER and any applicable Distribution Determination is set out in this table and Table 5.2.
6.18.3(a)	Define the tariff classes into which customers for direct control services are divided.	Tariff classes applicable to customers for direct control services are set out and justified in Sections 6.1 and 7.1. As noted above, the number of tariff classes for Standard Control Services has been reduced in 2015–16 (refer to Section 8.3.3) and there have been some changes to tariff classes for Alternative Control Services (refer to Section 8.3.1).
6.18.3(b)	Demonstrate that each customer for direct control services is a member of at least one tariff class.	Assignment of each customer to a tariff class is demonstrated in Sections 6.1 and 7.1.
6.18.3 (c)	Set out separate tariff classes for Standard Control Services and Alternative Control Services.	Tariff classes for Standard and Alternative Control Services are set out in Sections 6.1 and 7.1.
6.18.3(d)(1)	Demonstrate that tariff classes are formed based on groupings of customers on an economically efficient basis.	A description of how tariff classes group customers on an economically efficient basis is set out in Sections 6.1 and 7.1. Default Metering Services and Public Lighting Services are provided to customers who require those services and grouping is undertaken on this basis.

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
6.18.3(d)(2)	Demonstrate that customers and tariffs are grouped into tariff classes with regard to the need to avoid unnecessary transaction costs.	A description of how tariffs are grouped into tariff classes with regard to the need to avoid unnecessary transactions costs is set out in Sections 6.1 and 7.1. Consolidation of major customer tariff classes reduces complexity with no loss of individual pricing outcomes. Default Metering Services and Public Lighting Services are provided to customers who require those services and grouping is undertaken on this basis.
6.18.4(a)(1)(i), (ii) and (iii)	Demonstrate that customers are assigned (or re-assigned) to tariff classes on the basis of the nature and extent of their usage and the nature of their connection to the network, and that Ergon Energy has regard to the metering installed at a customer's premises when deciding whether to group a tariff into a broader tariff class.	Tariff assignment is dealt with in Sections 6.2 and 7.2.
6.18.4(a)(2)	Demonstrate that customers with a similar usage and connection profile are treated on an equal basis.	Tariff assignment is dealt with in Sections 6.2 and 7.2.
6.18.4(a)(3)	Demonstrate that customers with micro-generation facilities are treated on a basis no less favourable to customers without such facilities.	Tariff assignment is dealt with in Sections 6.2 and 7.2.
6.18.4(a)(4)	Demonstrate that customer assignment and reassignment to a tariff class does not occur in the absence of an effective system of assessment and review.	Tariff assignment is dealt with in Sections 6.2 and 7.2.
6.18.4(b)	Set out the system of assessment and review of the basis on which a customer is charged, if the charging parameters for a tariff vary according to the customer's usage or load profile.	Tariff assignment and the assessment and review of the basis of charge are dealt with in Sections 6.2 and 7.2.
6.18.5(a)(1) and (2)	Demonstrate that revenue from a tariff class lies on or between the stand alone and avoidable cost.	Stand alone and avoidable cost assessments are provided in Sections 6.7 and 7.5. The approach to these estimates is provided in Appendix 2. The reduction in tariff classes has been reflected in this table.
6.18.5(b)(1)	Demonstrate that tariffs and charging parameters have regard for Long Run Marginal Cost (LRMC).	Ergon Energy has reviewed our calculation of LRMC and has considered LRMC and associated economic pricing principles when progressing the introduction of new optional cost reflective network tariffs. LRMC is dealt with in Sections 6.8 and 7.6.
6.18.5(b)(2)(i)	Demonstrate that tariffs and charging parameters have been determined having regard to the transaction costs associated with the tariff or each charging parameter.	We have had regard to transaction cost impacts from our tariffs, particularly in the context of the introduction of new tariffs in 2015–16. Complexity may increase transaction costs. However, because many of these tariffs are optional, customers will have choice in whether to adopt the tariff or remain on default tariffs with lower transaction costs. Further information on tariffs and transaction costs is contained in Sections 6.9 and 7.6.

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
6.18.5(b)(2)(ii)	Demonstrate that tariffs and charging parameters are set with regard to whether customers will respond to signals.	Tariffs and signals are dealt with in Sections 6.10 and 7.6.
6.18.5(c)	Demonstrate that if tariffs do not recover the required revenue as a result of the operation of 6.18.5(b), that tariffs have been adjusted with minimum distortion.	This is dealt with in Section 8.1.
6.18.6 (a) and (b)	Demonstrate that the weighted average revenue for a Standard Control Service tariff class does not exceed that for the previous year by more than the "permissible percentage" defined in 6.18.6(c) of the NER.	Side constraints are not applied between regulatory control periods. Therefore, side constraints do not apply to tariff classes in 2015–16.
6.18.6(c)(1) and (2)	Demonstrate the "permissible percentage" has been calculated in accordance with the definition set out in this clause of the NER.	The permissible percentage was not calculated for the above reason.
6.18.6(d)(1), (2) and (3)	Demonstrate that designated pricing proposal charges (TUOS), pass throughs and jurisdictional scheme amounts were removed from the calculation of the side constraint.	The permissible percentage was not calculated for the above reason.
6.18.6(e)	Demonstrate that the side constraints have not impacted on the extent to which the tariffs for a customer with remotely read interval metering will vary according to usage.	The permissible percentage was not calculated for the above reason.
6.18.7(a)	Demonstrate that the tariffs passed on, to customers, the designated pricing proposal charges (TUOS) to be incurred by Ergon Energy for TUOS services.	Designated pricing proposal charges (TUOS) passed on to customers are dealt with in Section 6.12.
6.18.7(b)	Demonstrate that the designated pricing proposal charges (TUOS) passed on to customers do not exceed the forecast charges adjusted for over or under recovery.	Designated pricing proposal charges (TUOS) passed on to customers are dealt with in Section 6.12.
6.18.7(c)(1), (2) and (3)	Demonstrate that any designated pricing proposal charges (TUOS) over or under recovery is the difference between the amount actually paid and what was recovered from customers via TUOS charges, is consistent with the Final Determination and adjusts for the appropriate cost of capital.	Designated pricing proposal charges (TUOS) passed on to customers are dealt with in Section 6.12.
6.18.7A (a), (b) and (c)	Demonstrate that tariffs passed on, to customers, the jurisdictional scheme amounts to be incurred by Ergon Energy for approved jurisdictional schemes in accordance with 6.18.7A of the NER.	Appendix C of Attachment 14 to the Preliminary Determination outlines Ergon Energy's requirements in respect of passing on jurisdictional scheme amounts. Our approach to applying jurisdictional scheme amounts to customer tariffs is provided in Section 6.13.
6.18.8(a)(2)	Demonstrate that all forecasts associated with the proposal are reasonable.	Ergon Energy has made some changes to tariff structures and introduced new tariff and tariff components in 2015–16. Nevertheless, the methodology used to forecast customer numbers, energy consumption, demand and TUOS payments is consistent with the overarching method used by Ergon Energy in 2014–15. Further information is contained in Section 8.4.
6.18.9(a)(1)	Demonstrate that tariffs classes and the tariffs applicable to each class are maintained on Ergon Energy's website.	This Pricing Proposal will be published on Ergon Energy's website.

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
6.18.9(a)(2)	Demonstrate that charging parameters are maintained on Ergon Energy's website.	This Pricing Proposal will be published on Ergon Energy's website.
6.18.9(a)(3)	Demonstrate that Ergon Energy maintains on its website a statement of expected price trends (to be updated each regulatory year) giving an indication of how it expects prices to change over the regulatory control period and the reasons for the expected changes.	The expected price trends are set out in Appendix 6 and will be published separately on our website.
6.18.9(b)	Demonstrate that the posting of information for a particular regulatory year must, if practicable, be posted on Ergon Energy's website 20 business days before the commencement of the relevant regulatory year and, if that is not practicable, as soon as practicable thereafter.	This Pricing Proposal will be published on Ergon Energy's website by the appropriate date. Ergon Energy's supporting network pricing documentation, as set out in Section 1.5, will also be published on our website.

Table 5.2: Compliance with the Preliminary Determination

Obligation	Demonstration of compliance in this Pricing Proposal
Demonstrate that our revenue is consistent with the TAR formula set out in Figure 14.1 of Attachment 14 of the Preliminary Determination, plus any unders and overs adjustment needed to move the balance of the DUOS unders and overs account to zero.	This is demonstrated in Section 6.5 and Appendix 2.
Demonstrate the side constraints applying to the price movements of each tariff class are consistent with the formula in Figure 14.2 of Attachment 14 of the Preliminary Determination.	Side constraints do not apply in 2015–16.
Submit as part of the annual pricing proposal, a record of the amount of revenue recovered from designated pricing proposal charges and associated payments in accordance with appendix B of Attachment 14 of the Preliminary Determination.	Our TUOS unders and overs account is set out in Section 6.12.2. This section details the revenue to be recovered from TUOS charges.
Report the jurisdictional scheme amounts recovery in accordance with appendix C of Attachment 14 of the Preliminary Determination.	Our jurisdictional scheme unders and overs account is set out in Section 6.13.2. This section details the jurisdictional scheme amount we expect to recover from customers in 2015-16.
Apply the procedures for assigning retail customers to tariff classes or reassigning retail customers from one tariff class to another as set out in appendix D of Attachment 14 of the Preliminary Determination.	Tariff assignment and the assessment and review of the basis of charge are dealt with in Sections 6.2 and 7.2. Ergon Energy will apply these procedures in 2015–16.
Maintain a DUOS unders and overs account in accordance with appendix A of Attachment 14 of the Preliminary Determination. The expected closing balance at the end of each regulatory year t should be zero.	Our DUOS unders and overs account is set out in Section 6.5.2. This section also details the unders/overs adjustments needed to move the balance of the DUOS unders and overs account to zero.
Maintain a TUOS unders and overs account in accordance with appendix B of Attachment 14 of the Preliminary Determination. The expected closing balance at the end of each regulatory year t should be zero.	Our TUOS unders and overs account is set out in Section 6.12.2. This section also details the unders/overs adjustments needed to move the balance of the TUOS unders and overs account to zero.
Maintain a jurisdictional scheme unders and overs account in accordance with appendix C of Attachment 14 of the Preliminary Determination. The expected closing balance at the end of each regulatory year t should be zero.	Our jurisdictional scheme unders and overs account is set out in Section 6.13.2. This section also details the unders/overs adjustments needed to move the balance of the jurisdictional scheme unders and overs account to zero.

Obligation	Demonstration of compliance in this Pricing Proposal
For Standard Control Services, apply the X-factor for each year of the regulatory control period as determined in the PTRM and annually revised for the return on debt update in accordance with the formula specified in appendix I of Attachment 3 of the Preliminary Determination.	In 2015–16, Ergon Energy has applied the relevant revenue allowances set out in the Preliminary Determination and PTRM. We note this amount already incorporates the first year return on debt.
Ensure the raw labour rates applying to our fee based and quoted services in 2015–16 are less than or equal to the maximum raw labour rates set out in Table 16.4 of the Preliminary Determination.	Ergon Energy confirms the raw (base) labour rates applying to our fee based and quoted services in 2015–16 are less than or equal to the maximum labour rates determined by the AER. The calculation of fee based and quoted services is set out in Appendix 5.
Ensure the overhead rates applying to our fee based and quoted services are less than or equal to the maximum overhead rate of 65 per cent.	Ergon Energy confirms the overhead rates applying to our fee based and quoted services are less than or equal to 65 per cent. The calculation of fee based and quoted services is set out in Appendix 5.
Ensure the labour on cost rate applying to our fee based and quoted services is less than or equal to the maximum labour on cost rate of 43.5 per cent.	Ergon Energy confirms the labour on cost rates applying to our fee based and quoted services are less than or equal to 43.5 per cent. The calculation of fee based and quoted services is set out in Appendix 5.
Annually adjust individual price caps for Default Metering Services in accordance with the control mechanism set out in section 16.2.1.5 of Attachment 16 of the Preliminary Determination.	Since the AER has determined the regulated annual charges to apply in 2015–16 in its Preliminary Determination, Ergon Energy does not need to demonstrate compliance with the individual price cap for regulated annual charges. Our compliance with the individual price cap for the upfront charges is demonstrated in Appendix 5.
Demonstrate that individual prices for Default Metering Services are less than or equal to the approved price cap for that individual service by providing a copy of the published price list for that year.	Ergon Energy's individual prices for regulated annual charges are the same as the charges determined by the AER in its Preliminary Determination. The individual prices for individual upfront capital charges equal the approved price cap prices. This is illustrated in Appendix 5. These prices are published in this Pricing Proposal and will be available in our *Price List for Alternative Control Services*, once approved by the AER.

6 Standard Control Services

6.1 Tariff classes

The NER requires Ergon Energy to establish tariff classes with regard to the need to group customers on an economically efficient basis, and the need to avoid transaction costs. Essentially this requires a balance to be struck between having a large number of tariff classes which may provide economic efficiency benefits (such as sending customised signals to customers whose cost of supply are roughly equivalent) – and the transaction costs that would be involved in developing and implementing such a large number of different tariff classes.

For 2015–16, Ergon Energy's selection of Standard Control Service tariff classes follows our cost allocation process for tariff setting by differentiating between:

- customer groupings – being ICC, CAC, SAC and EG network users
- zones – being East, West and Mount Isa.

This is different to 2014–15, in that we no longer differentiate our ICC, CAC and EG tariff classes according to whether the customer is subject to the previous arrangements where connection assets form part of the network tariff or the Major Customer Connection process where new or augmented connection assets are paid or contributed by the customer. Given the small number of customers in the post 30 June 2010 tariff classes, we have decided to streamline the number of tariff classes.[22] The number of tariff classes is now more closely aligned with industry practice. We intend to further review our tariff classes as part of our preparation and consultation on the Tariff Structure Statement (TSS) in 2015.

Consolidation of tariff classes has not impacted on price outcomes for individual customers. This is because tariffs are determined at the individual customer or tariff level rather than at the tariff class level.

The consequent tariff classes under this approach are set out in Table 6.1 below, thus meeting the requirements of clause 6.18.2(b)(1)[23] and clause 6.18.3(a)[24] of the NER. There are 18 tariff classes for Standard Control Services.

Table 6.1: Ergon Energy's Standard Control Service tariff classes

Tariff class	Tariff	Network Tariff Codes
Individually Calculated Customer – East	ICC	EICCKA1 onwards EICCKB1 onwards
Individually Calculated Customer – West	ICC	WICCKA1 onwards WICCKB1 onwards
Individually Calculated Customer – Mount Isa	ICC	MICCKA1 onwards MICCKB1 onwards
Connection Asset Customer – East	CAC 66 kV	EC66T1, EC66T2, EC66T3
	CAC 33 kV	EC33T1, EC33T2, EC33T3
	CAC 22/11 kV Bus	EC22BT1, EC22BT2, EC22BT3

22 Ergon Energy will notify affected customers' retailers in accordance with our tariff class reassignment procedures outlined in Section 6.2.

23 This clause requires a Pricing Proposal to set out the tariff classes that are to apply for the relevant regulatory year.

24 This clause requires a Pricing Proposal to define the tariff classes into which customers for direct control services are divided.

Tariff class	Tariff	Network Tariff Codes
	CAC 22/11 kV Line	EC22LT1, EC22LT2, EC22LT3
	Seasonal TOU Demand CAC Higher Voltage (66/33 kV)	EC66TOUT1, EC66TOUT2, EC66TOUT3
	Seasonal TOU Demand CAC 22/11 kV Bus	EC22BTOUT1, EC22BTOUT2, EC22BTOUT3
	Seasonal TOU Demand CAC 22/11 kV Line	EC22LTOUT1, EC22LTOUT2, EC22LTOUT3
Connection Asset Customer – West	CAC 66 kV	WC66T1, WC66T2, WC66T3
	CAC 33 kV	WC33T1, WC33T2, WC33T3
	CAC 22/11 kV Bus	WC22BT1, WC22BT2, WC22BT3
	CAC 22/11 kV Line	WC22LT1, WC22LT2, WC22LT3
	Seasonal TOU Demand CAC Higher Voltage (66/33 kV)	WC66TOUT1, WC66TOUT2, WC66TOUT3
	Seasonal TOU Demand CAC 22/11 kV Bus	WC22BTOUT1, WC22BTOUT2, WC22BTOUT3
	Seasonal TOU Demand CAC 22/11 kV Line	WC22LTOUT1, WC22LTOUT2, WC22LTOUT3
Connection Asset Customer – Mount Isa	CAC 66 kV	MC66T4
	CAC 33 kV	MC33T4
	CAC 22/11 kV Bus	MC22BT4
	CAC 22/11 kV Line	MC22LT4
	Seasonal TOU Demand CAC Higher Voltage (66/33 kV)	MC66TOUT4
	Seasonal TOU Demand CAC 22/11 kV Bus	MC22BTOUT4
	Seasonal TOU Demand CAC 22/11 kV Line	MC22LTOUT4
Embedded Generation – East	EG	EEGA1 onwards EEGB1 onwards
Embedded Generation – West	EG	WEGA1 onwards WEGB1 onwards
Embedded Generation – Mount Isa	EG	MEGA1 onwards MEGB1 onwards
Standard Asset Customer – Large (>100 MWh p.a.) – East	Demand High Voltage	EDHTT1, EDHTT2, EDHTT3, EDHTCT1, EDHTCT2, EDHTCT3
	Demand Large	EDLTT1, EDLTT2, EDLTT3, EDLTCT1, EDLTCT2, EDLTCT3
	Demand Medium	EDMTT1, EDMTT2, EDMTT3, EDMTCT1, EDMTCT2, EDMTCT3
	Demand Small	EDSTT1, EDSTT2, EDSTT3, EDSTCT1, EDSTCT2, EDSTCT3
	Seasonal TOU Demand	ESTOUDCT1, ESTOUDCT2, ESTOUDCT3
Standard Asset Customer – Large (>100 MWh p.a.) – West	Demand High Voltage	WDHTT1, WDHTT2, WDHTT3, WDHTCT1, WDHTCT2, WDHTCT3
	Demand Large	WDLTT1, WDLTT2, WDLTT3, WDLTCT1, WDLTCT2, WDLTCT3

Tariff class	Tariff	Network Tariff Codes
	Demand Medium	WDMTT1, WDMTT2, WDMTT3, WDMTCT1, WDMTCT2, WDMTCT3
	Demand Small	WDSTT1, WDSTT2, WDSTT3, WDSTCT1, WDSTCT2, WDSTCT3
	Seasonal TOU Demand	WSTOUDCT1, WSTOUDCT2, WSTOUDCT3
Standard Asset Customer – Large (>100 MWh p.a.) – Mount Isa	Demand High Voltage	MDHTT4, MDHTCT4
	Demand Large	MDLTT4, MDLTCT4
	Demand Medium	MDMTT4, MDMTCT4
	Demand Small	MDSTT4, MDSTCT4
	Seasonal TOU Demand	MSTOUDCT4
Standard Asset Customer – Small (<100 MWh p.a.) – East	IBT Business	EBIBT1, EBIBT2, EBIBT3, EBIBCT1, EBIBCT2, EBIBCT3
	Seasonal TOU Energy Business	EBTOUT1, EBTOUT2, EBTOUT3, EBTOUCT1, EBTOUCT2, EBTOUCT3
	Seasonal TOU Demand Business	EBTOUDCT1, EBTOUDCT2, EBTOUDCT3
	IBT Residential	ERIBT1, ERIBT2, ERIBT3, ERIBCT1, ERIBCT2, ERIBCT3
	Seasonal TOU Energy Residential	ERTOUT1, ERTOUT2, ERTOUT3, ERTOUCT1, ERTOUCT2, ERTOUCT3
	Seasonal TOU Demand Residential	ERTOUDCT1, ERTOUDCT2, ERTOUDCT3
	Volume Controlled	EVCT1, EVCT2, EVCT3, EVCCT1, EVCCT2, EVCCT3
	Volume Night Controlled	EVNT1, EVNT2, EVNT3, EVNCT1, EVNCT2, EVNCT3
Standard Asset Customer – Small (<100 MWh p.a.) – West	IBT Business	WBIBT1, WBIBT2, WBIBT3, WBIBCT1, WBIBCT2, WBIBCT3
	Seasonal TOU Energy Business	WBTOUT1, WBTOUT2, WBTOUT3, WBTOUCT1, WBTOUCT2, WBTOUCT3
	Seasonal TOU Demand Business	WBTOUDCT1, WBTOUDCT2, WBTOUDCT3
	IBT Residential	WRIBT1, WRIBT2, WRIBT3, WRIBCT1, WRIBCT2, WRIBCT3
	Seasonal TOU Energy Residential	WRTOUT1, WRTOUT2, WRTOUT3, WRTOUCT1, WRTOUCT2, WRTOUCT3
	Seasonal TOU Demand Residential	WRTOUDCT1, WRTOUDCT2, WRTOUDCT3
	Volume Controlled	WVCT1, WVCT2, WVCT3, WVCCT1, WVCCT2, WVCCT3
	Volume Night Controlled	WVNT1, WVNT2, WVNT3, WVNCT1, WVNCT2, WVNCT3
Standard Asset Customer – Small (<100 MWh p.a.) – Mount Isa	IBT Business	MBIBT4, MBIBCT4
	Seasonal TOU Energy Business	MBTOUT4, MBTOUCT4
	Seasonal TOU Demand Business	MBTOUDCT4
	IBT Residential	MRIBT4, MRIBCT4
	Seasonal TOU Energy Residential	MRTOUT4, MRTOUCT4

Tariff class	Tariff	Network Tariff Codes
	Seasonal TOU Demand Residential	MRTOUDCT4
	Volume Controlled	MVCT4, MVCCT4
	Volume Night Controlled	MVNT4, MVNCT4
Standard Asset Customer – Unmetered – East	Volume Unmetered	EVUT1, EVUT2, EVUT3 EVUMIT1, EVUMIT2, EVUMIT3 EVUMAT1, EVUMAT2, EVUMAT3
Standard Asset Customer – Unmetered – West	Volume Unmetered	WVUT1, WVUT2, WVUT3 WVUMIT1, WVUMIT2, WVUMIT3 WVUMAT1, WVUMAT2, WVUMAT3
Standard Asset Customer – Unmetered – Mount Isa	Volume Unmetered	MVUT4, MVUMIT4, MVUMAT4

In accordance with clause 6.18.3(b) of the NER, all of Ergon Energy's customers for Standard Control Services are a member of one or more tariff classes. This is because:

- all of Ergon Energy's customers are assigned to at least one network tariff in the Distribution Cost of Supply (DCOS) Model, and no customers are priced outside this model
- all network tariffs calculated by the DCOS Model are allocated to Standard Control Service tariff classes (Standard Control Services being a subset of direct control services).

Consistent with clause 6.18.3(c) of the NER, Ergon Energy assigns customers receiving Standard Control Services to one of the tariff classes listed in Table 6.1. Separately, Ergon Energy provides tariff classes for customers seeking Alternative Control Services, as demonstrated in Section 7.1.

Finally, clause 6.18.3(d) of the NER requires that a tariff class be constituted with regard to the need to group customers together on an economically efficient basis, and the need to avoid unnecessary transactions costs. This requires a balance to be struck between setting tariffs that send efficient signals to customers – which, in principle, will vary according to each individual customer's size, consumption pattern/profile and location/feeder within the network – and minimising the costs of developing and implementing a large number of bespoke tariffs.

Ergon Energy's Tariff Setting Objective and Pricing Principles Philosophy[25] notes that our pricing methodologies are developed according to the principle that network tariffs are an equitable reflection of the network user's utilisation of the existing network, while minimising the inefficiency of price averaging. This approach helps ensure that customers with broadly similar characteristics, who impose similar costs on the network, are classed together so that they face similar tariff structures.

Our tariff class groupings follow the process of revenue allocation consistent with these principles, as outlined in Section 3. The tariffs within each tariff class have been grouped together in a manner that is easy for customers and retailers to understand, which avoids unnecessary transaction costs.

In 2014–15, Ergon Energy subdivided our SAC <100 MWh p.a. group into 'Residential' and 'Business' categories to better reflect the typically different load profiles of residential and business customers. This helps promote economic efficiency while avoiding costly tariff proliferation.

In 2015–16, we are introducing a change to our CAC tariffs that will reduce unpublished individual pricing of 179 customers to four published standard tariffs in each of the East and West zones. Through the introduction of a specific individual number of connection units for each customer it has been possible to offer the standard tariff regardless of network connection date, original connection funding mechanism or connection configuration. This approach maintains existing customer cost

[25] Refer to Appendix 1 of Ergon Energy's *Information Guide for Standard Control Services Pricing*.

reflectivity while simplifying tariffs for both new and existing customers and retailers, and reduces our on-going tariff support cost.

6.2 Assignment and reassignment of customers to tariff classes

Attachment 14 of the Preliminary Determination sets out the AER's procedures for assigning or reassigning customers to tariff classes. When formulating these provisions, clause 6.18.4(a) of the NER requires the AER to have regard to the following principles:

> *(1) Customers should be assigned to tariff classes on the basis of one or more of the following factors:*
>
> > *(i) the nature and extent of their usage*
> >
> > *(ii) the nature of their connection to the network*
> >
> > *(iii) whether remotely-read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.*
>
> *(2) Customers with a similar connection and usage profile should be treated on an equal basis.*
>
> *(3) Customers with micro-generation facilities should be treated no less favourably than customers without such facilities but with a similar load profile.*
>
> *(4) A DNSP's decision to assign a customer to a particular tariff class, or to re-assign a customer from one tariff class to another should be subject to an effective system of assessment and review.*

Further, under clause 6.18.4(b) of the NER and Attachment 14 of the Preliminary Determination, Ergon Energy's Pricing Proposal must also contain provisions for an effective system of assessment and review of the basis on which a customer is charged, if the charging parameters for a particular tariff result in a basis of charge that varies according to the usage or load profile of the customer.

Ergon Energy's compliance with these requirements for Standard Control Service tariff classes is set out in the remainder of Section 6.2 below.

6.2.1 Review of a customer's assigned tariff class

Assignment or reassignment of customers to Ergon Energy's Standard Control Service tariff classes occurs as a result of:

- new connections to the network
- existing customers applying for increased capacity on the network
- a change in a customer's National Metering Identifier (NMI) classification
- annual review as part of the process of developing and submitting the Pricing Proposal for approval by the AER
- requests for a review of the assigned network tariff or tariff class by either a customer and/or retailer.

Clauses 6.18.4(a)(1) and (2) of the NER are met because Ergon Energy assigns customers to tariff classes on the basis of geographical location, usage and size. Customers are first classified into the East, West or Mount Isa zones, based on geographical location. In order to provide the appropriate economic and cost of supply signals, customers are then assigned into one of four network user groups.

Further, customers with micro-generation facilities are charged the same network tariff for supply to their connection point as any other network customer with a similar load profile (in the absence of micro-generation), thus satisfying clause 6.18.4(a)(3) of the NER.

Ergon Energy relies on a range of information and has specific criteria for assessing the assignment and reassignment of customers to tariff classes. The following range of information and criteria (as set out in Table 6.2 below) is used when determining a customer's network user group, and tariff class assignment or reassignment details:

- historical consumption data
- expected annual consumption for new customers or those customers who have a written agreement to change their supply capacity
- the customer's geographical location and assets utilised in connecting to the network.

Ergon Energy also interrogates various internal systems to obtain site-specific connection asset arrangements.

It is important to note that Ergon Energy does not reassign customers without careful review and adequate justification. Reassignment generally occurs in a situation where a customer alters the underlying characteristics of their connection, in terms of size or nature of usage, in that it would no longer be appropriate for the customer to remain assigned to that tariff class.

Once a customer is identified for reassignment, the connection characteristics and the customer's expected energy consumption are used to determine the appropriate customer group, and hence tariff class, to which the customer should be reassigned.

Table 6.2: Tariff class assignment and reassignment criteria for Standard Control Services

Network user group	Typical characteristics of customers assigned	Criteria for reassigning customers to a different tariff class
SAC	▪ Annual consumption is expected to be below 4 GWh p.a.	▪ Annual consumption increases, or is expected to increase, above 4 GWh p.a., and/or ▪ A customer requests an increase in supply capacity requiring augmentation to connection assets which results in a dedicated supply system which is quite different and separate from the remainder of the supply network.
CAC	▪ Required capacity above 1,500 kVA, or ▪ Annual consumption is expected to exceed 4 GWh p.a.	Reassigned to ICCs: ▪ Annual consumption increases, or is expected to increase, above 40 GWh p.a., and/or ▪ A customer requests an increase in supply capacity requiring augmentation to their connection assets which results in a dedicated supply system which is quite different and separate from the remainder of the supply network. Reassigned to SACs: ▪ Annual consumption reduces or is expected to reduce below 4 GWh p.a. and their dedicated supply system is not considered to be quite different and separate from the remainder of the supply network, and/or ▪ Required capacity falls below 1,500 kVA.[26]

[26] With the exception of those customers who have a dedicated supply system which is quite different and separate from the remainder of the supply network or where inequitable treatment of otherwise comparable customers will arise from the application of the 4 GWh p.a. threshold.

Network user group	Typical characteristics of customers assigned	Criteria for reassigning customers to a different tariff class
ICC	▪ Annual consumption is expected to exceed 40 GWh p.a., or ▪ Their dedicated supply system is considered to be quite different and separate from the remainder of the supply network.	▪ Annual consumption reduces or is expected to reduce below 40 GWh p.a. and their dedicated supply system is considered comparable with CACs at the same voltage level.

6.2.2 Review of the charging basis

Consistent with 6.18.4(b) of the NER, Ergon Energy has a system for assessing and reviewing the basis on which a customer is charged.

Ergon Energy may review the charging basis where:

- a change in the usage, load profile or customer classification (i.e. business or residential for SACs <100 MWh p.a.) of a customer may mean a different network tariff is more applicable, or
- within a network tariff, it is appropriate to change the charging parameter/s because of changes relating to the customer's usage. For example, an additional charging parameter may be included once usage reaches a certain level.

Ergon Energy annually reviews the assignment of customers to our tariff classes as part of the process of developing and submitting our Pricing Proposal to the AER for approval. In undertaking this review, Ergon Energy uses set procedures and specific criteria (as set out in Table 6.2 above) to determine when it is appropriate for a customer to be reassigned to a tariff class as a result of material change in the customer's energy consumption or connection characteristics. These procedures, in conjunction with the classification of SACs <100 MWh p.a. as business or residential, by default also ensure the customer's underlying network tariff associated with a tariff class also remains appropriate.

In addition to this annual review process, customers and/or retailers can expressly request Ergon Energy to review and change a network tariff assigned to a customer in the event of variation to the customer's usage, load profile or classification as a business or residential customer. Provided that Ergon Energy agrees to the change in network tariff, this change can take effect during a regulatory year. Ergon Energy uses the procedures and specific criteria set out above to determine if it is appropriate to change the network tariff assigned to a customer. Further information on network tariff reviews is contained in our *Information Guide for Standard Control Services Pricing*.

With respect to variations in the basis of charge within a network tariff, Ergon Energy can confirm that the charging parameters (e.g. fixed, capacity, demand, and volume charges) within our network tariffs do not alter as the customer's usage or load profile varies. That is, the structure and rates of each charging parameter within a tariff apply equally to each customer assigned to the network tariff regardless of a customer's individual usage or load profile.

However, for SACs <100 MWh p.a. on an Inclining Block Tariff (IBT), the actual network charges applied to them will vary according to their level of usage. Similarly, for customers on Time-of-Use (TOU) tariffs, the network charges will vary according to when their usage (demand or energy, depending on the tariff) occurs. For our ICCs, the excess kVAr charge may also apply to customers with a poor power factor.

Should a customer's usage or load profile vary, the customer can either manage their usage by responding to the price signals inherent in the charging parameters of the tariff, or request to be reassigned to an alternative network tariff (if applicable) that may be more cost-effective for the customer's revised requirements.

6.2.3 Notification of a tariff class assignment and reassignment

Once Ergon Energy has assigned or reviewed the assignment of a customer to a Standard Control Service tariff class, written notification is provided to the customer's retailer prior to the assignment or reassignment occurring. The written notice includes:

- advice that the retailer may request further information from Ergon Energy and that they may object to the proposed assignment or reassignment
- a link to Ergon Energy's website where a copy of the internal procedures for reviewing objections is located
- advice that resolution is available via the Queensland Energy and Water Ombudsman (to the extent resolution of such disputes are within their jurisdiction), if the objection is not resolved by Ergon Energy to the satisfaction of the parties
- otherwise advice that resolution is available via the dispute resolution process under Part 10 of the Law.

In addition, the *Information Guide for Standard Control Services* sets out the circumstances when a tariff class assignment and reassignment may occur, and provides details on how the retailer can request further information on a tariff class assignment, and the procedures to follow if the retailer objects to a proposed tariff class assignment or reassignment.

6.2.4 Objections to a tariff class assignment or reassignment

If the retailer raises an objection to a tariff class assignment or reassignment, the matter is reviewed and, if required, escalated to the Manager Regulatory Determination and Pricing for reassessment.

Following this internal review, should the matter not be resolved to the satisfaction of the retailer, the retailer is entitled to refer the matter to:

- the Queensland Water and Energy Ombudsman
- the AER for resolution via the dispute resolution process available under Part 10 of the Law and clause 6.22.1 of the NER.

At the time of preparing this Pricing Proposal, Ergon Energy had received 18 objections to a tariff class assignment or reassignment relating to Standard Control Services that occurred during the 2014–15 regulatory year. None of these objections were escalated for reassessment.

6.3 Tariff charging parameters

The network tariffs comprise a number of charging parameters, each selected and structured to provide signals to network users about the efficient use of the network. Changes being introduced to tariffs, particularly the new LRMC based optional tariffs, are designed to promote the efficient use of the network to customers and reflect the impact of their usage on future network capacity and costs.

It is noted that in alignment with LRMC based pricing principles, charging parameters are no longer built up based exclusively on recovery of historic cost based allocation relationships. Charging parameters are populated firstly to reflect LRMC and then to recover residual revenue in a way which minimises distortion from optimal customer response to the LRMC parameters. The approach adopted by Ergon Energy to LRMC pricing is discussed in more detail in Section 6.8.

The following charging parameters have been adopted in 2015–16.

6.3.1 Fixed charges

Fixed charges, levied on a rate per day basis, apply to all network users, but not all tariffs. In the case of the STOUD tariff for SAC <100 MWh p.a. residential and business customers, no explicit fixed charge applies. However, a minimum off-peak chargeable demand of 3 kW per month is applied in the nine non-summer months.

A minimum off-peak chargeable demand is also applied in the optional STOUD tariff offered to CAC customers in the nine non-summer months as follows:

- 22/11 kV Line – 750 kVA
- 22/11 kV Bus – 850 kVA
- Higher Voltages – 1,000 kVA.

6.3.2 Connection unit charges

Traditionally for CACs, customer connection charges have been based on their specific connection configuration and presented explicitly through individual tariffs. In 2015–16, it is proposed to represent this connection charge (same charge level) in a revised format which supports simplification and standardisation of charges to the CAC network user group. The framework proposed is based on the establishment of a standard daily connection charge which is multiplied by an individual customer number of connection units to calculate an individual customer connection charge.

Customers will be individually advised of the connection unit multiplier value attributed to their NMI and this would remain unchanged other than for a significant change in connection arrangements.

This separation of the customer's individual connection unit multiplier and a standard fixed connection charge is similar to capacity charging where each CAC customer has their individual authorised demand applied against a standard fixed capacity rate. Further explanation is provided in Section 8.3.2.

6.3.3 Capacity and demand charges

LRMC/peak charge components

Setting the level and structure of the peak charge component under demand based tariffs is important in terms of establishing pricing mechanisms that reflect the LRMC of supply and are effective in providing a price signal to customers to reduce demand in peak network congestion periods. Setting the peak charge based on the LRMC encourages customers to invest in demand management technologies or change their behaviour only to the extent that it is cheaper (or more valuable to the customer) than the cost to Ergon Energy of increasing network capacity.

The peak components of the maximum demand tariffs in the 2015–16 suite of STOUD tariffs were designed based on considering alternative mechanisms for charging demand in the peak and shoulder periods. The mechanisms chosen are considered to be both cost reflective of the LRMC of the cost of supplying electricity and effective in enabling customers to respond to price signals.

The peak demand charges proposed in the 2015–16 tariffs are based on a transitional approach to signalling LRMC. We took into account customer concerns and impacts as well as the level of uncertainty and volatility in the LRMC value when determining the peak charge to apply.

In the LRMC based STOUD tariffs (applied at CAC, SAC >100 MWh p.a. and SAC <100 MWh p.a. level), actual demand charges have both a peak, and off-peak component. The peak demand charge relates to only demand during the peak periods in each month of the summer season.

Residual/Off-Peak charge components

Regulated revenue not recovered through the LRMC related charge should be recovered in a manner that has as little influence as possible on patterns of electricity demand. Ergon Energy considered a number of choices as options to recover residual costs.

These include:

- fixed charges ($/day)
- off-peak or anytime energy charge (c/kWh)
- off-peak network demand with or without a minimum chargeable demand ($/kW capacity).

The combinations proposed across the various user groups have been selected on efficiency and effectiveness as well as ability of customers to respond.

Demand charges are also utilised in the legacy tariffs available to ICCs, CACs, and SACs >100 MWh p.a. These charges are discussed further below.

Capacity charges

The capacity charge applies to ICC and CAC network users only.

The demand used for the calculation of the capacity charge is the authorised demand or, if there is no authorised demand, the annual maximum demand in the previous full pricing period prior to the setting of prices. Under certain circumstances, where there has been a significant change in demand attributable to a network user's load change after this previous pricing period, a more recent demand may be substituted.

Further, where the actual demand exceeds the authorised demand in any one month, the actual demand will be substituted for the authorised demand in the calculation of the capacity charge for that month.

Actual demand charges

Actual demand charges apply to all ICC, CAC and SAC >100 MWh p.a. customers and also to the SAC <100 MWh p.a. demand tariffs (Business and Residential STOUD).

For the legacy tariffs the actual monthly demand is based on the highest individual demand in any single half hour in the month. For ICCs and CACs, the demand is measured in kVA, and for SAC >100 MWh p.a. it is kW.

In the LRMC based STOUD tariffs (applied at CAC, SAC >100 MWh p.a. and SAC <100 MWh p.a. levels), actual demand charges link to both peak and off-peak charging parameters. The peak demand charge only relates to demand during the peak periods in each month of the summer season.

For SAC <100 MWh p.a. the demand is the average of an extended period of time referred to as 'average top four extended'. For residential customers the calculation of the actual peak demand uses the customer's top four peak demand days (based on daily individual maximum half hour kW demand) in the peak window (3:00 pm to 9:30 pm). This is a separate calculation in each summer month (i.e. December, January and February). The demand charge will be applied to the <u>average</u> kW demand calculated for the total 52 half hour periods each month (i.e. 13 half hour intervals in each peak window x four (4) peak demand days). A similar approach is used for business customers except business peak days and hours apply.

Excess reactive power (kVAr) charges

This charge applies to ICC network users only. It reinforces the kVA price signal to customers operating at non-compliant power factors, encouraging these customers to improve their power factor to a compliant level and reduce their network capacity usage. The charge only impacts customers where their power factor is non-compliant and consuming a quantity of kVAr which is greater than what is implicit in their capacity demand charge (the permissible kVAr quantity). Excess kVAr is calculated monthly based on the amount by which a customer's individual peak monthly kVAr exceeds their permissible kVArs.

6.3.4 Volume charges

In the LRMC tariffs, the volume charge contributes to the recovery of residual revenue.

The volume charge applies to the energy (kWh) metered at the customer's installation and may be based on a flat rate, an inclining block or TOU charging structure (depending on the applicable network tariff).

6.4 Tariff schedules

Clause 6.18.2(b)(2) of the NER requires Ergon Energy to set out the proposed tariffs for each tariff class. Accordingly, the 2015–16 tariffs for Standard Control Services are set out in Appendix 1 and Appendix 2.

6.5 Revenue is consistent with TAR formula

Attachment 14 of the Preliminary Determination requires Ergon Energy to demonstrate in our Pricing Proposal that the proposed tariffs and charging parameters which lead to expected revenue are consistent with the Total Annual Revenue (TAR) formula, plus any unders or overs adjustment needed to move the balance of the DUOS unders and overs account to zero.

6.5.1 Calculation of the TAR

In accordance with section 14.5.3 of Attachment 14 of the Preliminary Determination, Ergon Energy applies the following formulae when calculating the smoothed expected revenue and the TAR for a given regulatory year:[27]

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

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

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

Where:

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

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

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

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

27 Ergon Energy received a letter from the AER on 20 May 2015 advising us to include "DUOS$_t$" in formula 2 to correct an error contained in the Preliminary Determination.

TAR_t is the total annual revenue in year t

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

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

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

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

C_t is the sum of adjustments related to:

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

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

The resulting revenue cap for 2015–16, and the underlying calculations, is provided in Appendix 2. Ergon Energy confirms that the expected revenue to be collected from our network tariffs is less than the TAR, plus any unders or overs adjustment needed to move the balance of the DUOS unders and overs account to zero.[28]

Ergon Energy notes that, at the time of submitting this Pricing Proposal, the AER had not yet approved the s-factor to apply to 2015–16 prices. Following discussions with the AER, Ergon Energy is proposing to apply an s-factor of 2 per cent in the revenue cap calculation for 2015–16, by utilising an approach to bank the difference between the s-factor outcome from the transitional revenue at risk cap limit calculated for 2015–16 and 2 per cent. This approach is considered reasonable given it also takes into account the fact that the AER's Substitute Determination is due by the end of October 2015 and, necessarily, the X_0 adjustment to account for step changes in revenue between regulatory control periods (applied to derive the final s-factor) will be updated at this stage.

To the extent the AER later determines that the s-factor relating to our 2013–14 performance is different to the 2 per cent applied, Ergon Energy proposes any adjustment be taken into account in the 2016–17 s-factor and revenue cap calculations. This is subject to approval by the AER as part of this Pricing Proposal.

Ergon Energy welcomes further discussion from the AER on how the s-factors should be calculated taking into account step changes in revenue between regulatory control periods and any other consequential changes required to calculations as a result of how the s-factor is now reflected in the revenue cap formula in the Preliminary Determination.

6.5.2 DUOS unders and overs account

Under a revenue cap, our revenues are adjusted annually to clear any under or over recovery of actual revenue collected through DUOS charges. This 'unders and overs' rebalancing process is undertaken as part of annual pricing to ensure the we recover no more and no less than the TAR approved by the AER for any given year.

[28] As noted above, Ergon Energy has included "$DUOS_t$" in formula 2 following advice from the AER.

Under these arrangements there is generally a two year lag between the year in which the DUOS under or over recovery occurs and the year in which adjustments are made to prices to 'clear' the under or over recovery. For example, for prices set in 2015–16, the adjustment will relate to actual under or over recoveries in the 2013–14 regulatory year.

Under appendix A of Attachment 14 of the Preliminary Determination, Ergon Energy must maintain our DUOS unders and overs account which is to be provided to the AER in this Pricing Proposal. It also notes that "the proposed prices for year *t* are based on the sum of the total annual revenue for year *t* plus any adjustment for DUOS under or over recoveries".[29]

Table 6.3 sets out the DUOS unders and overs account, in accordance with Attachment 14 of the Preliminary Determination.

Table 6.3: Calculation of DUOS unders and overs account ($'000)

	2013–14 Year t-2 (actual)	2015–16 Year t (forecast)
Revenue from DUOS charges	$1,536,760	$1,444,147
Less Total Annual Revenue for the relevant year	$1,592,501	$1,377,043
Annual Smooth Expected Revenue (AR_t)	$1,501,088	$1,160,467
Incentive scheme adjustments (I_t)	$1,846	$0
DUOS under/over adjustment approved by the regulator for year t-2 ($DUOS_t$)	$32,052	n/a
Transitional under/over adjustments (capital contributions and shared assets) (B_t)	$71,858	$81,545
Approved pass throughs and other adjustments (C_t)	($14,344)	$135,031
Actual under/over recovery year t-2 (proposed under/over adjustment in year t)	($55,741)	$67,104
<u>DUOS unders and overs account</u>		
Nominal WACC for year t-2	9.72%	
Nominal WACC for year t-1	9.72%	
Opening balance	$0	($67,104)
Interest on opening balance for 1 regulatory year	$0	n/a
Actual under / over recovery in year t-2 (proposed under/over adjustment in year t)	($55,741)	$67,104
Interest on under / over recovery for 2 regulatory years	($11,363)	n/a
Closing balance	($67,104)	$0

29 AER (2015), *Preliminary Decision, Ergon Energy Determination 2015–16 to 2019–20, Attachment 14 – Control Mechanisms*, April 2015, p19.

6.6 Forecast weighted average revenue for each tariff class

Clause 6.18.2(b)(4) of the NER requires Ergon Energy to set out, for each tariff class related to Standard Control Services, the expected weighted average revenue for the relevant regulatory year and also for the current regulatory year. This is shown in Appendix 3.

6.7 Avoidable and stand alone costs

Clause 6.18.5(a) of the NER requires that for each tariff class, the revenue expected to be recovered lie on or between an upper bound representing the stand alone cost of serving the customers who belong to that class and a lower bound representing the avoidable cost of not serving those customers.

The NER do not specifically define stand alone and avoidable costs or set out the methodology that should be applied to calculate these costs. Consequently, Ergon Energy interprets these costs in the following manner:

- **Stand alone costs** for a tariff class are the costs of establishing and maintaining infrastructure to service a single tariff class. They represent the upper bound costs of providing a service for a particular tariff class. Assuming that no other tariff classes use network infrastructure means that the economies of scale from multiple tariff classes using a shared network are ignored.
- **Avoidable costs** are the costs which would be avoided by Ergon Energy not providing a distribution service to a particular tariff class. Thus, if Ergon Energy was to cease providing services to CACs in our West Zone, the avoidable cost methodology assesses which of our costs could be avoided.

The approach taken to determine stand alone and avoidable cost varies between Standard Control Services and Alternative Control Services. The processes for Standard Control Services are described in the following sections. Section 7.5 sets out the processes for Alternative Control Services.

6.7.1 Stand alone costs

Ergon Energy has revised our estimate of the stand alone costs for each tariff class by calculating the total annual costs of operating the network, less the cost of serving all other tariff classes. This approach uses the revenue cap as a first step, which is allocated to tariffs using the DCOS Model. The network is assumed to remain in its current state with supply voltages unchanged. Individual classes of assets[30] are 'optimised' by notionally removing some.

Ergon Energy's assessment of the stand alone cost was determined from a review of the network in response to the following question:

> *"If XX tariff class was the only one supplied from the network, what percentage reduction in the value of existing assets employed in category YY could be made but still enable the same standard of network service to be provided to tariff class XX."*

Ergon Energy's assessment of the stand alone cost was based on our DCOS Model. An overall review of the network asset footprint and values has enabled an improved assessment of cost allocations across all user groups. We have made slight refinements in our approach on this basis.

Ergon Energy has determined the stand alone costs for groupings of similar Standard Control Service tariff classes (e.g. high voltage connected customers) by determining the portion of the revenue cap that could be avoided if all other tariff groupings were not served.

[30] It should be noted that Ergon Energy has removed metering assets which have been classified as an Alternative Control Service from our DCOS Model and stand alone and avoidable cost calculations.

6.7.2 Avoidable costs

To determine the avoidable costs of each grouping of similar tariff classes, Ergon Energy used a similar approach to the stand alone calculation, based on the DCOS Model and its allocation of the revenue cap. In this case, the cost was determined in response to the following question:

> *"If XX tariff class was not supplied from the network, what percentage reduction in the value of existing assets employed in category YY could be made but still enable the same standard of network service to be provided to all remaining tariff classes".*

As with the stand alone costs, Ergon Energy has determined the avoidable costs for groupings of similar Standard Control Service tariff classes by estimating the notional portion of the revenue cap that could be avoided, if the tariff grouping under consideration was not served.

6.7.3 Comparison of avoidable costs, expected revenue and stand alone costs

The NER defines a tariff class as follows:

> A class of *retail customers* for one or more *direct control services* who are subject to a particular tariff or particular tariffs.

Further, the Law defines a retail customer as:

> A person to whom electricity is sold by a retailer, and supplied in respect of connection points, for the premises of the person, and includes a person (or a person who is of a class of persons) prescribed by the Rules for the purposes of this definition.

As such, Ergon Energy does not apply the avoidable and stand alone cost test to our EG tariff classes as they are not 'retail customers' under the Law. The tariffs we assign to these customers recover the cost of dedicated connection assets for the generator and do not reflect their use of the shared network.

Table 6.4 below demonstrates that, for each Standard Control Service tariff class containing retail customers, the 2015–16 expected revenue for each tariff class lies on or between the lower bound avoidable cost and an upper bound stand alone cost, in accordance with clause 6.18.5(a) of the NER.

The calculation of these amounts is demonstrated in Appendix 2.

Table 6.4: Avoidable costs, expected revenue and stand alone costs for Standard Control Services (GST Exclusive)

Tariff class	Avoidable costs	Expected revenue	Stand alone costs	Clause 6.18.5(a) met
Individually Calculated Customer – East	$9,051,716	$42,037,078	$388,848,874	Yes
Individually Calculated Customer – West	$2,408,396	$14,532,459	$108,270,960	Yes
Individually Calculated Customer – Mount Isa	$0	$0	$0	Yes
Connection Asset Customer – East	$20,957,981	$83,705,894	$619,144,526	Yes
Connection Asset Customer – West	$5,864,470	$11,107,977	$165,736,843	Yes
Connection Asset Customer – Mount Isa	$0	$0	$0	Yes
Standard Asset Customer – Large (>100 MWh p.a.) – East	$34,027,777	$305,940,529	$319,902,462	Yes

Tariff class	Avoidable costs	Expected revenue	Stand alone costs	Clause 6.18.5(a) met
Standard Asset Customer – Large (>100 MWh p.a.) – West	$9,067,811	$83,355,733	$86,703,506	Yes
Standard Asset Customer – Large (>100 MWh p.a.) – Mount Isa	$545,923	$4,370,693	$4,649,441	Yes
Standard Asset Customer – Small (<100 MWh p.a.) – East	$182,814,373	$667,097,974	$767,807,708	Yes
Standard Asset Customer – Small (<100 MWh p.a.) – West	$48,924,539	$202,473,795	$208,707,413	Yes
Standard Asset Customer – Small (<100 MWh p.a.) – Mount Isa	$2,914,926	$10,306,850	$11,083,343	Yes
Standard Asset Customer – Unmetered – East	$82,319	$13,722,328	$632,651,821	Yes
Standard Asset Customer – Unmetered – West	$22,030	$2,023,059	$175,184,619	Yes
Standard Asset Customer – Unmetered – Mount Isa	$1,313	$300,718	$8,685,828	Yes

6.8 Long Run Marginal Cost

Clause 6.18.5(b)(1) of the NER requires that each tariff and, if it consists of two or more charging parameters, each charging parameter of a tariff class must take into account the LRMC for the service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates.

The Australian Energy Market Commission's (AEMC) recent rule change (Distribution Network Pricing Arrangements 2014) places new obligations on Ergon Energy going forward, in relation to how LRMC is calculated and applied to the LRMC requirements.[31]

The Pricing Principles now set out in clause 6.18.5(f) of the NER were amended on 1 December 2014 following that rule change. They require each tariff to be based on the LRMC of providing the service, having regard to:[32]

- the costs and benefits associated with calculating, implementing and applying the method
- the additional costs associated with meeting incremental demand for the customers assigned to the tariff for the relevant part of the distribution network
- the location of customers and the extent to which costs vary between different locations.

The NER now defines LRMC as the cost of an incremental change in demand for direct control services provided by a DNSP over a period of time in which all factors of production required to provide those services can be varied. This definition incorporates the investment required over time to expand capacity in the network to meet rising demand.

The NER does not define a method of determining LRMC. Nor in the associated Determination did the AEMC recommend an approach. The AEMC concluded:[33]

> *"The Commission considers that there is merit in providing flexibility to use either the AIC or Perturbation methodologies, or other accepted methodologies, depending on how strong the LRMC price signals need to be in order to send signals to consumers about the cost or benefit of undertaking or deferring additional network expenditure."*

[31] Refer to http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements.
[32] AEMC (2014), *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 No 9*, 27 November 2014.
[33] AEMC (2014), *Rule Determination – National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014, p118.

While these changes do not apply to this Pricing Proposal due to transitional arrangements,[34] we have amended our approach to LRMC in 2015–16. A summary of these changes is provided in Table 6.5.

Table 6.5: Summary of changes to LRMC

Issue	Proposed changes
Choice of method for calculating LRMC	▪ Movement away from the Benchmark Cost of Supply (BCS) to the Average Incremental Cost (AIC) approach with separate verification using a Long Run Incremental Cost (LRIC) approach ▪ Consistency check against LRIC model as used by United Kingdom (UK) distributors (termed the 500 MW model)
Costs to be included in LRMC for AIC	▪ Network demand related capital costs ▪ Incremental operating and maintenance expenditure associated with the demand related capital costs
Approach to estimating LRMC using LRIC	▪ A hypothetical greenfield model to supply a demand of 500 MW using modern asset replacement, operation and maintenance costs ▪ Model uses Ergon Energy's system configuration and voltage levels and achievable levels of asset utilisation
Allocation of LRMC to peak charges	▪ Given the relatively large difference between current peak charges and LRMC based peak charges, we are proposing a transitional allocation of LRMC to the peak charge in 2015–16
Application of LRMC to tariffs	▪ For existing tariffs – comparison with demand or peak period energy rates with a view to their progressive alignment ▪ For SAC >100 MWh p.a. – application to the customer's maximum demand on potential peak days during peak times in each summer month ▪ For SAC <100 MWh p.a. – application to the average of the customer's demand recorded during peak times for the highest four peak demand days in the month in the STOUD tariff and equalisation of the peak and shoulder energy rates in the Season Time-of-Use Energy (STOUE) tariff ▪ For CAC STOUD tariffs – incorporation into the peak capacity charge applied over the summer peak period

We have been consulting with customers on our approach to calculating the LRMC. We released the following papers this year:

- Aligning network charges to the cost of peak demand
- Long Run Marginal Cost considerations in developing network tariffs
- Estimating the Average Incremental Cost of Ergon Energy's Distribution Network
- Maximum Demand Tariff Analysis Report.[35]

These papers focus on our review of our LRMC calculation and the consequential changes to our peak energy and demand rates. We noted in our consultation that the revised LRMC was higher than the value previously applied. We consulted on possible transitional approaches to the allocation of LRMC to peak charging components, noting that immediate transition to our LRMC value has the following challenges:

- LRMC calculations are based on expectations on growth, expenditure and rate of return as at the time of our Regulatory Proposal last year. Forward projections will not be finalised until the AER's Substitute Determination in October 2015. However, based on the Preliminary

[34] NER, clause 11.73.1(b).
[35] Available at: http://www.ergon.com.au/futurenetworktariffs.

Determination, the AER's expectations of future costs are likely to be lower than what we proposed, suggesting the LRMC value may decrease.

- Most tariffs with a peak charging component based on LRMC are optional for customers. While this has advantages in that customers on default tariffs are unaffected by the change, Ergon Energy still needs to provide incentive for customers on default tariffs to transition. Therefore, we need to take into account customers' willingness to move to an optional tariff with no transition to a new LRMC value.

Based on our consultation with customers, and our own analysis, Ergon Energy has applied the values contained in Table 6.6 to the peak charge:

Table 6.6: LRMC charges

User group	Region	LRMC applied per annum
CAC - 22/11 kV Lines	East	$145.50 / kVA
	West	$722.50 / kVA
CAC - 22/11 kV Bus	East	$100.00 / kVA
	West	$500.00 / kVA
CAC - Higher voltages	East	$50.00 / kVA
	West	$250.00 / kVA
SAC > 100 MWh p.a.	East	$189.00 / kW
	West	$472.00 / kW
	Mount Isa	$189.00 / kW
SAC < 100 MWh p.a. Residential	East	$189.00 / kW
TOU Demand	West	$472.00 / kW
TOU Energy	West	$590.00 / kW
	Mount Isa	$189.00 / kW
SAC < 100 MWh p.a. Business	East	$189.00 / kW
TOU Demand	West	$472.00 / kW
TOU Energy	West	$590.00 / kW
	Mount Isa	$189.00 / kW

The LRMC applied for the West Zone is impacted by the sparse footprint of customers in this zone. Previous analysis suggested an uplift factor of 2.5 times the East Zone level. However, Ergon Energy does not have granular information on growth and expenditure sufficient to calibrate a specific LRMC in the West Zone at this time. This will be further investigated as part of the TSS preparation.

Overall, Ergon Energy will continue to consult on the LRMC value and the transition in allocating LRMC values to peak charges as part of our further consultation for the TSS.

The application of LRMC to legacy tariffs is more challenging, given the lack of correlation between the cost of incremental change in demand and the charging parameters within each legacy tariff. Nevertheless, in line with previous years, Ergon Energy has determined the proportion of our regulated revenue to be recovered from each tariff class using the below method.

Ergon Energy allocates the TAR to tariff classes on the basis of:

- the number of customers connected to the network. This allocator is appropriate for those costs that are dependent upon or driven by the number of connected customers.
  Ergon Energy has a number of costs that are customer number based, including a significant

proportion of the overhead costs of the business that are driven by the number of staff and systems required to serve the customer base.

- any time energy. This is used to allocate those costs that are related to the size of the customer but not specifically to the demand that customer places on the network (e.g. network operating costs). In addition, consistent with the recovery mechanisms used in the electricity market, costs that cannot be directly related to a product or service are recovered through the use of any time energy prices (e.g. some overhead costs).
- Any Time Maximum Demand (ATMD). This method of allocation is used for shared system costs, on the basis that network development is driven by peak demand.
- asset value. This is used to apportion ROA, depreciation and opex costs.

6.9 Transaction costs

Clause 6.18.5(b)(2)(i) of the NER requires each tariff and, if it consists of two or more charging parameters, each charging parameter for a tariff class to be developed having regard to transaction costs associated with the tariff or charging parameter. 'Transaction costs' in this context refer to the costs to Ergon Energy, retailers and customers of designing/developing and implementing economically efficient tariffs. In the absence of this requirement, a narrow interpretation of economic efficiency could suggest that every customer at a different connection point should face a unique tariff to reflect the precise LRMC of network services at their location. However, such an approach would impose extremely high development, implementation and on-going transactional costs, would be unstable and at this time is not considered to be economically efficient or beneficial.

Ergon Energy confirms that we have had regard to the transaction costs when selecting our tariffs and charging parameters of tariff classes. Demand-based tariffs proposed in 2015–16 have an increased level of sophistication and complication compared to default tariffs which are limited to daily fixed and anytime energy consumption. There is a necessary trade-off when moving to more cost-reflective tariffs which we have considered. However, Ergon Energy notes, that for the most part, customers now have the option to move to more cost-reflective tariffs. Therefore, customers have more choice and control in how they are charged for their use of the network and can make their own informed decisions on which tariff they prefer.

For 2015–16, Ergon Energy has altered the structure or format of some of our network tariffs from those applying in the previous regulatory year. They are:

- Pre and post 30 June 2010 tariff classes for ICCs, CACs and EGs have been consolidated into single classes for each network user group.
- An additional charging component has been introduced for ICC customers. The excess kVAr charge is designed to provide an incentive for customers to meet the power factor requirements of the NER and legislation.
- CAC tariffs have been standardised by adopting a standard 'connection unit' charge and application of the standard TUOS region pricing.
- The cost reflectivity of CAC prices has been improved by changing their demand and capacity charges to kVA, rather than kW.
- The differential between the SAC <100 MWh p.a. STOUE tariff peak and shoulder energy rates has been set to zero to align more closely with the peak / off-peak structure in the STOUD tariff.

In formulating future changes to our network tariffs, Ergon Energy has and will continue to place considerable weight on the implementation costs incurred by both ourselves and our customers associated with the introduction of more sophisticated tariff structures and the cost trade-off associated with tariffs that do not align with Ergon Energy costs and therefore drive sub-optimal investment in the network by customers.

6.10 Response to price signals

Clause 6.18.5(b)(2)(ii) of the NER requires each tariff and, if it consists of two or more charging parameters, each charging parameter for a tariff class to be developed having regard to whether customers of the relevant tariff class are able or likely to respond to price signals.

As a result of tariff reform Ergon Energy is transitioning to explicit LRMC based tariffs. We have a number of legacy default tariffs that are offered in parallel with the new optional LRMC based tariffs.

LRMC tariffs introduce new and different pricing principles to the legacy tariffs. Legacy tariffs have been developed using the cost allocation methodology detailed in Section 6.3. Effectively, Ergon Energy's tariffs are in transition from a backward looking accounting based interpretation of historic cost-causality to a forward looking LRMC basis incorporating effective economical pricing principles that inform efficient and optimal usage of the network.

LRMC pricing principles result in a two part tariff outcome. The first part promulgates the LRMC price signal while the second part addresses residual revenue recovery. In developing the new LRMC tariffs, our objective has been to present the LRMC component through parameters which are as cost reflective as possible and aligned with enabling customer responses that support optimal use (or not) of the network.

In establishing and populating the parameters to recover residual revenue, Ergon Energy has targeted minimising any distortionary impact of the non-LRMC based parameters on customer response to the LRMC signals.

Therefore, Ergon Energy's tariffs have been established with a view to developing LRMC tariff parameters that customers are likely, and able to respond to, while choosing and calibrating residual recovery parameters that are less likely to distort the LRMC signals, encourage inefficient use of the network, or encourage inefficient by-pass.

Basically we have calibrated the LRMC tariffs to maximise response to the LRMC parameter and minimise response to the other parameters.

In applying these principles in 2015–16 we have not adopted full incorporation of the LRMC in the LRMC parameter. Instead, we are adopting a transitional approach which is expected to see the LRMC parameter progressively become stronger while the residual components are reduced.

Consistent with the above, the LRMC is recovered over a relatively short proportion of the year. The LRMC period for Ergon Energy is calibrated seasonally (December, January and February), by day of week, and by time of day. Peak times are different between the residential and business customer segments for SAC <100 MWh p.a. customers. The LRMC is calibrated in demand (kW for SAC and kVA for CAC) for STOUD tariffs. A STOUE tariff is also offered for SAC <100 MWh p.a. customers.

The peak demand parameter price has not only been set with a view to customers being able to respond to the LRMC price signal, but also to ensure that the signal is active only when additional demand on the network is likely to contribute to driving future network augmentation.

The role of the remaining parameters is recovery of residual revenue with as little distortionary impact on network usage as possible. The fixed, off-peak demand and volume (kWh) parameters have been calibrated to support minimal customer demand response.

For ICCs, we have introduced an excess kVAr charge. This charge is applied against kVAr drawn from the network that exceeds the minimum compliant power factor level. Essentially this charge reinforces the price signal introduced by the change to the kVA tariff, which encourages customers to improve power factor and reduce their usage of network capacity.

6.11 Expected price trends

Clause 6.18.9(a)(3) of the NER requires Ergon Energy to provide a statement of expected price trends, to be updated each regulatory year, that gives an indication of how we expect prices to change over the regulatory control period and the reasons for the expected changes.

Appendix 6 sets out price trends based on current information for the remainder of the regulatory control period (i.e. 2016–17 to 2019–20). We have limited our analysis to the East Zone as indicative trends in this zone are representative of others.

Our assessment of price trends necessitates assumptions of revenue, demand and energy forecasts based on current information and allocating the impacts of these forecasts to existing rates on an averaged basis. These price trends are highly indicative.

In Section 8.4, we highlight issues and uncertainties with respect to expectations of revenue, demand and energy. In particular, we note:

- the likelihood that future revenues will be adjusted as a result of the Substitute Determination in October 2015
- uncertainties regarding commodity prices which may impact economic conditions
- state government initiatives may impact our forecasts on the uptake of renewable energy.

Changes in prices will also be subject to any adjustments approved by the AER in the relevant year. This may include adjustments relating to:

- the difference between forecast and actual inflation
- the allowed rate of return
- our performance under the STPIS
- the Demand Management Incentive Scheme[36]
- any under or over-recoveries relating to capital contributions and shared assets from 2014–15
- DUOS under and over-recovery adjustments approved to be passed through in the relevant pricing year
- cost pass through amounts, including amounts associated with the Solar Bonus Scheme in 2014–15.

Outcomes from our Network Tariff Strategy, including customer response outcomes related to our reformed tariffs, may also impact network tariffs and prices.

For the purposes of indicative price trends, Ergon Energy has:

- applied the revenues from the Preliminary Determination, with no further adjustments
- included adjustments in the 2016–17 regulatory year for known under/over recovery adjustments and incentive scheme adjustments. We have assumed no adjustments in future years
- used high level assumptions regarding energy and demand forecasts, noting that revised energy and demand forecasts for the regulatory control period 2015–20 (which will be incorporated in our revised Regulatory Proposal in July 2015) are not finalised.

[36] Accounts for any amount of allowance unspent or not approved over the regulatory control period 2010–15 and the time value of money accrued/lost as a result of the expenditure profile selected by Ergon Energy. Applies in 2016–17 only.

Individual customer outcomes may differ significantly from the price trends indicated. This is particularly the case for major customers where changes in connection arrangements (e.g. authorised demand) can be a significant driver of future trends.

6.12 Designated pricing proposal charges incurred for TUOS

6.12.1 Allocation

Clause 6.18.7(a) of the NER requires Ergon Energy's Pricing Proposal to provide for tariffs designed to pass on to customers the designated pricing proposal charges to be incurred for TUOS services. This includes costs related to the payments of TUOS to Powerlink, Avoided TUOS payments to eligible EGs and payments to other DNSPs for the use of their network.

The allocation method is discussed in detail below.

Allocation of Powerlink charges

Powerlink charges Ergon Energy at an aggregated level by Transmission Connection Point which means that Ergon Energy needs to devise a methodology to apportion the various components of the Powerlink charges to customers. Ergon Energy's network tariff calculation process passes through Powerlink charges as cost reflectively as possible.

The TUOS charges charged to Ergon Energy by Powerlink at each Transmission Connection Point have four components:

- Entry/Exit Connection Price ($/month)
- Capped Customer TUOS Usage Price: Usage Capacity Price ($/kW/month of nominated demand plus $/kw/month average demand)
- Customer TUOS General Prices: General Energy Charge (c/kWh of historical energy)
- Transmission Customer Common Service Prices: Common Service Energy Price (c/kWh on historical energy).

These charges are apportioned by Ergon Energy to customers and/or customer groups on the basis of forecast ATMD with respect to the Entry/Exit Connection Price and the Usage Capacity Price, and apportioned on the basis of historical and forecast energy for the remaining components.

For SAC connections, charges for each Bulk Supply Point are allocated to one of three geographical TUOS Regions. TUOS charges are calculated based on the combined totals. This simplifies the tariffs, while still providing clear TUOS locational signals for these smaller customers.

As part of our network tariff reform, we have consulted with customers and retailers on prospective changes to CAC tariffs which eliminate the need for individual site-specific prices. These changes are outlined in Section 8.3.2. As part of this simplification process, Ergon Energy adjusted the TUOS component for CACs. The approach taken is similar to that for the SAC network user group, with charges for each Bulk Supply Point allocated to one of three geographical TUOS regions and charges being calculated on an aggregated regional basis. For those CACs that Ergon Energy deems to be a back-up supply, no fixed daily TUOS charge will apply in 2015–16. Further the authorised demand for back-up supplies will be set to zero. This means TUOS charges will only apply where the actual demand and metered energy at the customer's installation is greater than zero in any month. This is consistent with arrangements applying in the previous regulatory year.

In 2014–15, Ergon Energy represented TUOS charges to ICCs in kVA by applying a power factor adjustment to the recorded kW demand. This approach is now being proposed for both the ICC and CAC network user groups in 2015–16.

For ICC connections on site-specific charges, Ergon Energy takes into account the fact that customers can be supplied from different connection points depending on switching arrangements. Charges will continue to be apportioned based on the actual Bulk Supply Points the connection is supplied from. A weighted average methodology is applied for each of the Transmission Connection Points so that these site-specific connections have cost-reflective TUOS charges.

Network charges from other DNSPs

In the Toowoomba area, Ergon Energy utilises network services from the other Queensland DNSP, Energex, to supply a small group of customers that cannot be economically supplied from the Ergon Energy distribution system. Energex bills Ergon Energy a network service charge for these network services.

Additionally, in the Mount Isa Zone, Ergon Energy is charged for the use of the unregulated 220 kV network which supplies the Cloncurry township. The AER has determined that charges levied on Ergon Energy for the use of this network be recovered as designated pricing proposal charges.[37]

These costs are recovered by Ergon Energy as part of the TUOS charges passed through to customers.

Avoided TUOS payments

Where Ergon Energy is liable for an Avoided TUOS payment to an EG, the payment amount is recovered by Ergon Energy as part of the TUOS charges passed through to customers at the same connection point as the EG.

6.12.2 Recovery

Clause 6.18.7(b) of the NER requires that the amount to be passed on to customers for a particular regulatory year must not exceed the estimated amount of the designated pricing proposal (TUOS) charges for the relevant regulatory year adjusted for any over or under recovery.

Further, clause 6.18.7(c) of the NER states that:

> *The over and under recovery amount must be calculated in a way that:*
>
> *(1) subject to subparagraphs (2) and (3) below, is consistent with the method determined by the AER in the relevant distribution determination for the Distribution Network Service Provider;*
>
> *(2) ensures a Distribution Network Service Provider is able to recover from retail customers no more and no less than the designated pricing proposal charges it incurs; and*
>
> *(3) adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year.*

Attachment 14 of the Preliminary Determination sets out the requirements that Ergon Energy must comply with under clause 6.18.7 of the NER.

Ergon Energy ensures that any difference between TUOS revenue recovered from customers and the actual TUOS and related costs paid by Ergon Energy is offset by an annual unders and overs process. Under these arrangements there is a two year lag between the year in which the under-

[37] AER (2015), *Preliminary Decision, Ergon Energy Determination 2015–16 to 2019–20, Attachment 14 – Control Mechanisms*, April 2015, p13.

recovery or over-recovery occurs and the year in which the adjustment to the expected TUOS revenue to be recovered is made.

Table 6.7 below sets out Ergon Energy's 2013–14 under-recovery based on information lodged in our 2013–14 Annual Performance Regulatory Information Notice (RIN).[38] This table satisfies the requirements of Attachment 14 of the Preliminary Determination and hence clause 6.18.7 of the NER. Appendix 2 sets out the calculation of the TUOS unders and overs account.

Table 6.7: Calculation of TUOS unders and overs account ($'000)

	2013–14 Year t-2 (actual)	2015–16 Year t (forecast)
Revenue from TUOS charges	$332,574	$360,637
Less under/over adjustment approved by the regulator for year t-2 (from t-4)	$5,956	n/a
Less total transmission related payments	$329,303	$357,405
Transmission charges to be paid to TNSPs	$322,143	$349,856
Avoided TUOS payments	$3,793	$2,499
Inter-DNSP payments	$3,367	$5,050
Actual under/over recovery year t-2 (proposed under/over adjustment in year t)	($2,685)	$3,232
TUOS unders and overs account		
Nominal WACC for year t-2	9.72%	
Nominal WACC for year t-1	9.72%	
Opening balance	$0	($3,232)
Interest on opening balance for 1 regulatory year	$0	n/a
Actual under/over recovery in year t-2 (proposed under/over adjustment in year t)	($2,685)	$3,232
Interest on under/over recovery for 2 regulatory years	($547)	n/a
Closing balance	($3,232)	$0

[38] Ergon Energy has potentially identified an issue in relation to the total avoided TUOS payments included in the 2013–14 Annual Performance RIN. If this is confirmed, Ergon Energy will re-audit 2013–14 TUOS figures in our 2014–15 Annual Performance RIN.

6.13 Jurisdictional scheme amounts

As noted above, the Solar Bonus Scheme is the only jurisdictional scheme applying to Ergon Energy in 2015–16.

6.13.1 Jurisdictional scheme eligibility

Clause 6.18.2(b)(6B) of the NER requires our Pricing Proposal to describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria.

Ergon Energy notes the last jurisdictional scheme approval date for the Solar Bonus Scheme was 1 July 2010. Since that time, there have been a number of changes made to aspects of the scheme. A summary of these changes is set out in Table 6.8 below.

Table 6.8: Solar Bonus Scheme changes

Date	Summary of change
7 June 2011	Eligibility for 44 cents FiT rate changed – the maximum inverter size changed from 30kW to 5kW
9 July 2012	Applications for the 44 cents FiT rate closed. Customers who applied on this date or before will continue to receive the rate until 30 June 2028 providing ongoing eligibility requirements are met
10 July 2012	8 cents FiT rate commenced
23 November 2012	Eligibility for 44 cents FiT rate changed – existing customers must remain the electricity account holder for the premises where the solar PV system is connected (i.e. no account name changes allowed)
30 June 2014	8 cents FiT rate expired
1 July 2014	A government-mandated FiT was introduced in regional Queensland. This rate is determined by the Queensland Competition Authority (QCA) each year and is payable by Ergon Energy Queensland Pty Ltd (EEQ)

These changes have not affected the Solar Bonus Scheme's eligibility as a jurisdictional scheme. This is because Ergon Energy, in its capacity as a DNSP, is still required to pay FiT amounts to eligible persons under section 44A of the *Electricity Act 1994* until 30 June 2028. These amounts are not a fine, penalty or incentive payment for Ergon Energy, nor do we have a right to recover these amounts from any person.

6.13.2 Allocation

Clause 6.18.7A(a) of the NER requires Ergon Energy's Pricing Proposal to provide for tariffs designed to pass on to customers jurisdictional scheme amounts for approved jurisdictional schemes.

The Preliminary Determination was silent on the approach to allocating jurisdictional scheme amounts to various tariffs and tariff classes. In the regulatory control period 2010–15, FiT payments were recovered through DUOS charges. Therefore, for pricing purposes, the recovery of these costs was included in the standard revenue allocation process outlined in Section 3 above and allocated to various tariff classes on this basis.

In the absence of more specific instruction, revenue allocation in respect of jurisdictional scheme amounts will be allocated to tariff classes using an allocation process that is similar to how overhead costs incorporated in existing DUOS charges are allocated. The total revenue requirement for each tariff class is then converted to tariffs made up of a fixed charge ($/day) and a volume charge ($/kWh).

A benefit of having this separate tariff for jurisdictional scheme cost recovery is the ability to measure the associated revenue and make under/over adjustments in future periods.

6.13.3 Recovery

Clause 6.18.7A(b) of the NER requires that the amount to be passed on to customers for a particular regulatory year must not exceed the estimated amount of jurisdictional scheme amounts for a DNSP's approved jurisdictional schemes adjusted for any over or under recovery.

Further, clause 6.18.7A(c) of the NER states that:

> *The over and under recovery amount must be calculated in a way that:*
>
> *(1) subject to subparagraphs (2) and (3) below, is consistent with the method determined by the AER for jurisdictional scheme amounts in the relevant distribution determination for the Distribution Network Service Provider, or where no such method has been determined, with the method determined by the AER in the relevant distribution determination in respect of designated pricing proposal charges;*
>
> *(2) ensures a Distribution Network Service Provider is able to recover from customers no more and no less than the jurisdictional scheme amounts it incurs; and*
>
> *(3) adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year.*

Attachment 14 of the Preliminary Determination sets out the requirements that Ergon Energy must comply with under clause 6.18.7A of the NER. Specifically, Ergon Energy must provide the amounts for the following entries in their jurisdictional schemes unders and overs account for the most recently completed regulatory year (t–2) and the next regulatory year (t): [39]

1. Opening balance for year t–2 and year t.
2. An interest charge for two years on the opening balance in year t–2. This adjustment should be calculated using the approved nominal weighted average cost of capital (WACC). No such charge applies to the opening balance for year t.
3. The amount of revenue recovered from jurisdictional charges in respect of that year, less the amounts of all jurisdictional scheme related payments made by Ergon Energy in respect of that year.
4. An interest charge for two years related to the net amount in item 3 for year t–2. This adjustment should be calculated using the approved nominal WACC. No such charge applies to the net amount in item 3 for year t.
5. The total of items 1–4 to derive the closing balance for each year.

Ergon Energy must provide details of calculations in the format set out in Table 14.3 of the Preliminary Determination. Amounts provided for the most recently completed regulatory year (t–2) must be audited. Amounts for the next regulatory year (t) will be regarded as a forecast.

It is important to note actual FiT payments incurred by us in 2013–14 will be recovered through our network tariffs in 2015–16. This adjustment is made in the TAR formula, as a cost pass through amount.

[39] AER (2015), *Preliminary Decision, Ergon Energy Determination 2015–16 to 2019–20, Attachment 14 – Control Mechanisms*, April 2015, p23.

Table 6.9: Calculation of jurisdictional scheme unders and overs account ($'000)

	2013–14 Actual (t-2)	2015–16 Forecast (t)
Revenue from Jurisdictional charges	$0	$114,245
Less under/over adjustment approved by the regulator for year t-2 (from t-4)	$0	n/a
Less total jurisdictional related payments	$0	$114,245
Under/over recovery for the regulatory year	$0	$0
Jurisdictional Schemes unders and overs account		
Nominal WACC for year t-2	9.72%	
Nominal WACC for year t-1	9.72%	
Opening balance	$0	$0
Interest on opening balance for 1 regulatory year	$0	n/a
Under/over recovery in year t-2	$0	$0
Interest on under/over recovery for year t-2	$0	n/a
Closing balance	$0	$0

7 Alternative Control Services

7.1 Tariff classes

Ergon Energy's tariff classes for Alternative Control Services are differentiated at the highest level according to the AER's classification of services and the basis of pricing approved by the AER:

- fee based services
- quoted services
- Default Metering Services
- Public Lighting Services.

Fee based services are further separated into two tariff classes based on the type of feeder to which a customer requesting the service is connected.

Changes to the AER's classification of services for the regulatory control period 2015–20 have resulted in amendments to our existing tariff classes, as well as the introduction of a new tariff class. This includes:

- introducing a new tariff class for Default Metering Services, following the AER's decision to reclassify these services as an Alternative Control Service
- consolidating the three Street Lighting Services into one tariff class, due to the removal of geographical pricing.

The consequent tariff classes under this approach are set out in Table 7.1 below, thus meeting the requirements of clause 6.18.2(b)(1) and clause 6.18.3(a) of the NER. There are five tariff classes for Alternative Control Services.

Table 7.1: Ergon Energy's Alternative Control Service tariff classes

Tariff class	Product codes / tariff charging parameter code
Fee based services (urban/short rural)	CFDEENBHU, CFDEENBHS, CFREDDBHU, CFREDDBHS, CFREENBHU, CFREENBHS, CFSUPABOLU, CFSUPABOLS, CFTBSMPU, CFTBSMPS, CFTBSSPU, CFTBSSPS, DEENBHU, DEENBHS, REDDBHU, REDDBHS, REENBHU, REENBHS, SUPABOLU, SUPABOLS, TBSMPU, TBSMPS, TBSSPU, TBSSPS, WTVU, WTVS, WTVTU, WTVTS
Fee based services (long rural/isolated)	CFDEENBHL, CFDEENBHI, CFREDDBHL, CFREDDBHI, CFREENBHL, CFREENBHI, CFSUPABOLL, CFSUPABOLI, CFTBSMPL, CFTBSMPI, CFTBSSPL, CFTBSSPI, DEENBHL, DEENBHI, REDDBHL, REDDBHI, REENBHL, REENBHI, SUPABOLL, SUPABOLI, TBSMPL, TBSMPI, TBSSPL, TBSSPI, WTVL, WTVI, WTVTL, WTVTI
Quoted services	As Quoted, or ADDMTRU, ADDMTRS, ADDMTRL, ADDMTRI, CHLDCRCU, CHLDCRCS, CHLDCRCL, CHLDCRCI, CHTARIFU, CHTARIFS, CHTARIFL, CHTARIFI, CHTSRAU, CHTSRAS, CHTSRAL, CHTSRAI, CUSTAPTU, CUSTAPTS, CUSTAPTL, CUSTAPTI, DEENAHU, DEENAHS, DEENAHL, DEENAHI, HVSLDU, HVSLDS, HVSLDL, HVSLDI, INMTRLDCU, INMTRLDCS, INMTRLDCL, INMTRLDCI, LVSLDU, LVSLDS, LVSLDL, LVSLDI, MOVEMTRU, MOVEMTRS, MOVEMTRL, MOVEMTRI, MPOAU, MPOAS, MPOAL, MPOAI, MTRINSPU, MTRINSPS, MTRINSPL, MTRINSPI, MTRREPU, MTRREPS, MTRREPL, MTRREPI, MTRSEALU, MTRSEALS, MTRSEALL, MTRSEALI, MTRTESTU, MTRTESTS, MTRTESTL, MTRTESTI, PRCDMTRU, PRCDMTRS, PRCDMTRL, PRCDMTRI, REENAHU, REENAHS, REENAHL, REENAHI, RMLDCRLU,

Tariff class	Product codes / tariff charging parameter code
	RMLDCRLS, RMLDCRLL, RMLDCRLI, RMMTRU, RMMTRS, RMMTRL, RMMTRI, SPMTRRDU, SPMTRRDS, SPMTRRDL, SPMTRRDI, SUPENHU, SUPENHS, SUPENHL, SUPENHI, TEMPDEENU, TEMPDEENS, TEMPDEENL, TEMPDEENI, UNMTRSVCU, UNMTRSVCS, UNMTRSVCL, UNMTRSVCI
Default Metering Services	ACSMCC, ACSMNCC UPFTCSNGLU, UPFTCSNGLS, UPFTCSNGLL, UPFTCSNGLI, UPFTCDUALU, UPFTCDUALS, UPFTCDUALL, UPFTCDUALI, UPFTCTHREU, UPFTCTHRES, UPFTCTHREL, UPFTCTHREI
Public Lighting Services	ACSEOOMA, ACSEOOMI, ACSGEOMA, ACSGEOMI EOOMAEXT, EOOMIEXT, GEOMAEXT, GEOMIEXT

As indicated in Section 6.1 above, all of Ergon Energy's customers for direct control services are a member of one or more tariff classes (thus meeting clause 6.18.3(b) of the NER). This is because Alternative Control Services are a subset of direct control services and all of Ergon Energy's customers are assigned to at least one network tariff and one Standard Control Service tariff class. Further, clause 6.18.3(c) of the NER is met by Ergon Energy distinguishing between the tariff classes for Standard Control Services and for Alternative Control Services.

Finally, clause 6.18.3(d) of the NER requires that a tariff class be constituted with regard to the need to group customers together on an economically efficient basis, and the need to avoid unnecessary transaction costs. As noted above, this clause requires a balance to be struck between setting tariffs that send efficient signals to individual customers while minimising the costs of developing and implementing a large number of bespoke tariffs. Ergon Energy's tariffs for Alternative Control Services are grouped according to the classification and basis of pricing determined by the AER in its Preliminary Determination.

Table 7.1 outlines the groupings based on the service provided and, for fee based services, the type of feeder to which a customer requesting the service is connected. This aids in providing tariffs that appropriately reflect the costs incurred in providing the relevant service to the relevant type of customer. At the same time, the tariffs within each tariff class have been grouped together in a manner that is easy for customers and retailers to understand, which avoids unnecessary transaction costs as a result of tariff proliferation.

7.2 Assignment and reassignment of customers to tariff classes

The regulatory obligations relating to the assignment and reassignment of customers to tariff classes are set out in Section 6.2 above. Ergon Energy's compliance with these requirements for Alternative Control Service tariff classes is outlined below.

7.2.1 Review of a customer's assigned tariff class

Assignment or reassignment of customers to Ergon Energy's Alternative Control Service tariff classes occurs as a result of:

- major customers requesting a new connection to the network or an upgrade to their existing connection
- public lighting customers requesting installation of a new public light, or gifting a new public light to Ergon Energy
- small customers requesting a change to their metering arrangements (e.g. installing controlled load or solar, or choosing another provider if competition is introduced for Type 5 and 6 metering services)

- new service orders or works requests being raised as a result of a request for service by either a customer and/or retailer
- requests for a review of the assigned tariff class by either a customer and/or retailer.

Ergon Energy notes that tariffs for Alternative Control Services are allocated to tariff classes in accordance with the AER's Classification of Services and basis of pricing as set out in Attachments 13 and 16 of the Preliminary Determination. As such, customers essentially assign themselves to a tariff class by selecting the service that they require. Ergon Energy therefore considers we meet the requirements of clauses 6.18.4(a)(1), (2) and (3) of the NER and Attachment 13 of the Preliminary Determination because customers are assigned to tariff classes based on similar service requirements, without distinguishing between customers that have or do not have micro-generation facilities.

Ergon Energy's *Price List for Alternative Control Services* will set out which service belongs to each tariff class.

Similar to Standard Control Services, Ergon Energy does not reassign customers to tariff classes without careful review and adequate consideration. Ergon Energy uses the following range of criteria to assign new customers to a tariff class or to review the current assignment of customers to tariff classes for our Alternative Control Services:

- Fee based services – based on the:
  - type of service requested by either a customer and/or retailer
  - type of feeder to which the customer is connected (i.e. urban, short rural, long rural or isolated)
- Quoted services – based on the:
  - type of service requested by either a customer and/or retailer
- Default Metering Services – based on the:
  - type of service requested by either a customer and/or retailer
- Public Lighting Services – based on the:
  - type of service requested by either a customer and/or retailer
  - ownership basis.

7.2.2 Review of the charging basis

As the basis of charge and prices for these services is capped and/or developed using an approved formula, Ergon Energy considers the charging parameters of our Alternative Control Service tariffs do not vary according to the usage or load profile of a customer (as it does for Standard Control Services). Therefore, Ergon Energy considers that clause 6.18.4(b) of the NER does not apply to our Alternative Control Services. Consequently, Ergon Energy does not need to assess or review the basis (the approved formulae and price caps) on which a customer is charged for Alternative Control Services.

7.2.3 Notification of a tariff class assignment and reassignment

As noted above, customers essentially assign themselves to a tariff class by selecting the service that they require. Therefore, written notification of the tariff class is not provided by Ergon Energy to the retailer.

Retailers may request further information relating to a particular tariff class assignment or reassignment decision by contacting Ergon Energy.

7.2.4 Objections to a tariff class assignment or reassignment

Similar to Standard Control Services, if a retailer raises an objection to a tariff class assignment or reassignment for Alternative Control Services, the matter is reviewed and if required, escalated to the Manager Regulatory Determination and Pricing for reassessment. Following this internal review, if the matter is not resolved to the satisfaction of the retailer, the retailer is entitled to refer the matter to:

- the Queensland Water and Energy Ombudsman
- the AER for resolution via the dispute resolution process available under Part 10 of the Law and clause 6.22.1 of the NER.

The procedures a retailer can follow if they object to a proposed tariff class assignment or reassignment are set out in the publicly available *Information Guide for Alternative Control Services*.

At the time of preparing this Pricing Proposal, Ergon Energy had not received any objections to a tariff class assignment or reassignment relating to Alternative Control Services that occurred during the 2014–15 regulatory year.

7.3 Fee based and quoted services formula components

7.3.1 Changes in individual formula components for fee based and quoted services

Appendix A.1 of Attachment 16 of the Preliminary Determination sets out the prices Ergon Energy can charge for fee based services in 2015-16, as well as indicative prices for our quoted services. Ergon Energy has recalculated the escalators, labour on costs and overhead rates that apply to these services. Changes to the nature of these components and quantitative information to support the calculation are set out below and in Appendix 5.

Labour escalators

Due to the timing of our Regulatory Proposal, we applied annual CPI data to July quarter 2014 to develop our prices for fee based services and indicative prices for quoted services. We noted that we would update our prices for the annual CPI data to December quarter 2014 once it became available. Consequently, for the 2015–16 regulatory year, Ergon Energy has adjusted the nominal labour escalators contained in the Preliminary Determination by annual CPI data to December quarter 2014 as published by the ABS to develop prices for fee based services and indicative prices for quoted services.

This approach is consistent with the formulae that apply to fee based and quoted services in the remaining years of the regulatory control period. That is, these formulae reference the annual percentage change in CPI from December in year t-2 to December in year t-1.

Fleet escalators

For the 2015–16 regulatory year, Ergon Energy has adjusted the nominal fleet escalator contained in the Preliminary Determination by annual CPI data to December quarter 2014 as published by the ABS to develop prices for fee based services and indicative prices for quoted services.

Materials escalators

For the 2015–16 regulatory year, Ergon Energy has adjusted the nominal materials escalator contained in the Preliminary Determination by annual CPI data to December quarter 2014 as published by the ABS to develop indicative prices for quoted services.

There are no materials used in the provision of fee based services.

Contractor services escalators

For the 2015–16 regulatory year, Ergon Energy has adjusted the nominal contractor services escalator contained in the Preliminary Determination by annual CPI data to December quarter 2014 as published by the ABS to develop indicative prices for quoted services.

Contractor services do not apply in the provision of fee based services.

Labour on costs

For the 2015–16 regulatory year, Ergon Energy has applied the labour on cost rate contained in the Preliminary Determination to develop prices for fee based services and indicative prices for quoted services.

In reviewing the Preliminary Determination, we identified the AER has applied a labour on cost rate of 43.33 per cent to the base administration labour rate. This is different to the maximum labour on cost rate approved by the AER and the labour on cost rate that applies to other base labour rates. Ergon Energy considers this was an oversight and we have corrected our models for consistency.

Materials on costs

For the 2015–16 regulatory year, Ergon Energy has applied the material on cost rate contained in the Preliminary Determination to develop indicative prices for quoted services.

Overhead rates

Ergon Energy has recalculated the overhead rates.[40] Consistent with our AER-approved Cost Allocation Method (CAM),[41] Ergon Energy uses the following methodology to calculate the overhead rate for our fee based and quoted services:

1. **Determine total shared costs (overheads) for the regulatory year**. Budget data is used to set costs expected to relate to shared 'support' services which cannot be directly attributable to a particular activity or work plan. For example, shared costs include costs associated with business units that provide corporate support services across the Ergon Energy Group (Corporate Overheads). Shared costs also include costs associated with support services provided within Ergon Energy's operational business units that have not been directly attributed (Operational Overheads). Operational Overheads predominantly represent labour and administration costs associated with (but not limited to) senior management, technical and operations support, including maintenance and construction standards, mapping, technical data records and field investigations and auditing.
2. **Allocation of total shared costs (overheads) between Ergon Energy Group districts and Ergon Energy Corporation Limited Lines of Business (LOB)**. Ergon Energy Corporation Limited, as the parent entity of the Ergon Energy Group, provides 'support' services to a number of other districts (or legal entities) and LOB within EECL. These include:
   - *EEQ* – a subsidiary entity responsible for providing non-competing electricity retail services to non-market customers
   - *Ergon Energy Telecommunications Pty Ltd* – a subsidiary entity and licensed telecommunications carrier providing wholesale high-speed data capacity to the Ergon Energy Group and external customers

[40] Ergon Energy has not updated the overhead rate applying to the administration labour rate. Consistent with the Preliminary Determination, we have applied the AER's maximum overhead rate.

[41] Available at http://www.aer.gov.au/node/27108.

- *SPARQ Solutions Pty Ltd (SPARQ)* – a joint venture company formed by Ergon Energy and Energex providing information technology and telecommunications to Ergon Energy and Energex. Ergon Energy holds a 50 per cent share in SPARQ
- *Ergon Energy Corporation Limited LOBs* – the parent entity of EECL is broken down over various LOB – Regulated, Non-Regulated, Isolated System, External, Powerlink and Workshop Services.

Once the districts and total shared costs for the regulatory year are determined, the costs are then allocated to each entity in the Ergon Energy Group using causal allocators in accordance with the CAM and in some instances using a commercial agreement between Ergon Energy and SPARQ. The choice of allocator depends on the type of service provided. For example, where the shared costs are identified as relating solely to a legal entity within the Ergon Energy Group, costs are directly allocated to that entity. In other cases, the number of transactions undertaken or time spent in providing the service may be the driver to calculate the allocation of work and shared costs to each entity.

3. **Determine the direct costs for the regulated LOB.** Budget data is used to set costs expected to be directly attributable to regulated opex and capital expenditure (capex) required for delivering our work plans. These costs are determined using an Activity Based Costing Method which maps and directly attributes expected costs of particular activities to the Chart of Accounts.

4. **Allocation of shared (support) costs between regulated opex and capex activities**. For the pool of shared (support) costs that have been allocated to the regulated distribution services provided by Ergon Energy Corporation Limited, the next step is to allocate these shared (support) costs between regulated opex activities and regulated capex activities.

   Where the shared (support) cost is directly attributable to either regulated opex or regulated capex, the cost is charged directly to that activity.

   For shared (support) costs that are shared between operating and capital activities, the costs are allocated on the basis of the proportional values of the operating and capital work plans (i.e. direct costs).

   The outcome is a pool of shared (support) costs related to regulated opex activities and a pool of shared costs related to regulated capex activities.

5. **Calculate the overhead rate**. The shared (support) cost pools determined in Step 1 above are then converted to shared cost percentage rates for regulated opex activities and regulated capex activities as follows:

$$\text{Customer service Opex overhead rate \%} = \frac{\text{Shared cost for customer service opex activities}}{\text{Work plan costs for customer service opex activities}}$$

$$\text{General regulated Opex overhead rate \%} = \frac{\text{Shared cost for general regulated opex activities}}{\text{Work plan costs for general regulated opex activities}}$$

$$\text{General regulated Capex overhead rate \%} = \frac{\text{Shared cost for regulated capex activities}}{\text{Work plan costs for regulated capex activities}}$$

6. **Select appropriate overhead rate**. The overhead rate used by Ergon Energy for our fee based services and quoted services is the calculated overhead rate as explained above.

   For example, the regulated capex overhead rate applies to customer services capital work and the customer services opex overhead rate applies to customer services operational work. An exception to using the opex rate is when opex costs are capitalised. In these instances the regulated capex overhead rate will apply. For example, if Ergon Energy substantially relocates assets at the request of a customer which changes our network, then we expect to treat this as capex and we would apply the regulated capex overhead rate.

Ergon Energy's 2015–16 overhead rate calculation is provided in Appendix 5.

7.3.2 Changes in methodology employed to derive formula components

Ergon Energy has not varied or adjusted the methodology employed to derive the formula components from previous years.

7.4 Tariff schedules

Clause 6.18.2(b)(2) of the NER requires Ergon Energy to set out the proposed tariffs for each tariff class. Accordingly, the 2015–16 tariffs for Alternative Control Services are set out in Appendix 4.

7.5 Avoidable and stand alone costs

As noted in Section 6.7, clause 6.18.5(a) of the NER requires that for each tariff class, the revenue expected to be recovered lie on or between an upper bound representing the stand alone cost of serving the customers who belong to that class and a lower bound representing the avoidable cost of not serving those customers.

As per our interpretation of stand alone and avoidable costs in Section 6.7, Ergon Energy has set out below our approach to determining these costs for our fee based services, quoted services, Public Lighting Services and Default Metering Services.

Ergon Energy has not undertaken any quantitative analysis of our stand alone and avoidable costs for Alternative Control Services.

7.5.1 Fee based and quoted services

Ergon Energy provides our Alternative Control Services using a mix of shared and dedicated physical assets and labour. We price each of these services on a full cost recovery basis using the formula approved by the AER.

We note the AER must establish controls over the revenue recovered or prices paid for these services having regard to the NER and Law. We also note in the Preliminary Determination that it has determined charges based on what it believes will promote the efficient provision of electricity services and allow a return commensurate with the regulatory and commercial risks involved for the provision of those services.[42] If the AER has undertaken its task correctly, and Ergon Energy prices in accordance with the Preliminary Determination, then the outcomes of its decision will result in revenue recovery between the upper and lower bounds contemplated by the NER.

The use of a cost based formula for pricing implies that if there were only one Alternative Control Service tariff class provided by Ergon Energy, then total revenue for that tariff class would equal the total cost of serving that tariff class (where the total cost incurred in the provision of the service for that tariff class includes the full cost of assets used by all Alternative Control Services). This means the revenue received from one Alternative Control Service tariff class will not be greater than the stand alone cost of that tariff class.

The avoidable cost of Alternative Control Services is the cost incurred in the delivery of the services to a tariff class if no services were provided to any other tariff class. The only avoided costs relating to

[42] AER (2015), *Preliminary Decision, Ergon Energy Determination 2015–16 to 2019–20, Attachment 16 – Alternative Control Services*, April 2015, p11.

Alternative Control Services are labour costs charged on an hourly basis, materials consumed during the course of providing the service and contractor services costs incurred. Given that the formula used to derive prices for fee based and quoted services includes a component of shared costs, the total revenue for tariff classes will exceed the avoidable portion.

7.5.2 Public Lighting Services

Since Ergon Energy has proposed one Public Lighting Services tariff class, the revenue expected to be recovered from this tariff class will be equal to the allocation of the ARR for Public Lighting Services plus any additional revenue expected to be recovered through the exit fees. Ergon Energy intends to recover revenue consistent with the schedule of prices per light determined by the AER. These prices were based on the AER's own determination of efficient costs on a per unit basis, using a combination of high level benchmarking and assessing the assumptions used in the build-up of costs.

If the AER's task has been undertaken correctly, the determined prices will result in recovery of efficient costs and expected revenue will be between the upper and lower bounds contemplated by the NER.

7.5.3 Default Metering Services

Since Ergon Energy has proposed one Default Metering Services tariff class, the revenue expected to be recovered from this tariff class will be equal to the allocation of the ARR for Default Metering Services plus any additional revenue expected to be recovered through the upfront capital charges. Ergon Energy intends to recover revenue consistent with the schedule of prices per meter determined by the AER. These prices were based on the AER's own determination of efficient costs on a per unit basis, using a combination of high level benchmarking and assessing the assumptions used in the build-up of costs.

If the AER's task has been undertaken correctly, the determined prices will result in recovery of efficient costs and expected revenue between the upper and lower bounds contemplated by the NER.

7.6 Long Run Marginal Cost, transaction costs and response to price signals

The NER requires each tariff and, if it consists of two or more charging parameters, each charging parameter of a tariff class:

- to take into account the LRMC for the service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates (clause 6.18.5(b)(1))
- to be developed having regard to transaction costs associated with the tariff or charging parameter (clause 6.18.5(b)(2)(i))
- to be developed having regard to whether customers of the relevant tariff class are able or likely to respond to price signals (clause 6.18.5(b)(2)(ii)).

Ergon Energy's tariffs for fee based services, quoted services, Public Lighting Services and Default Metering Services comprise one charging parameter. Therefore, consistent with clause 6.18.5, Ergon Energy is not required to demonstrate compliance for individual charging parameters but rather just the individual tariffs. The tariff setting process outlined in Chapter 4 is largely determined through the control mechanism established by the AER in its Preliminary Determination. Therefore, each tariff and the movement in tariffs between regulatory years are determined by the AER through the control mechanism applied. In establishing these controls, the AER has regard to both the National Electricity Objective and Revenue and Pricing Principles.

Under the formula based approach, customers are sent signals about the true cost of the service that they are able to request. This helps ensure that customers will only use a service if they believe they will gain a larger benefit from the service than it costs Ergon Energy to provide that service in the long term. This helps ensure that Alternative Control Services are provided to customers up to the point where the marginal benefits from using the service equals the marginal costs that use of the service imposes on Ergon Energy. This is consistent with economic efficiency.

In the case of quoted services, customers will have incentives to consider whether a different variant of the service may be preferable (e.g. customers can minimise the cost incurred for some services by choosing to have the service delivered during business hours, if applicable). This, too, is consistent with economic efficiency principles.

By their nature, most Alternative Control Services are services requested by customers that vary according to the specific characteristics or circumstances of the customer. This suggests that customers have the ability and incentive to respond to cost reflective tariffs for these services.

7.7 Expected price trends

Clause 6.18.9(a)(3) of the NER requires Ergon Energy to provide a statement of expected price trends, to be updated each regulatory year, that gives an indication of how we expect prices to change over the regulatory control period and the reasons for the expected changes.

Appendix 6 sets out indicative prices for our Alternative Control Services. In general, prices are expected to change as a result of the following adjustments:

- the difference between forecast and actual inflation
- changes to underlying real costs (refer to Section 7.3 above).

8 Other compliance obligations

8.1 Tariff adjustment to address revenue shortfalls

Clause 6.18.5(c) of the NER provides that if, as a result of the operation of clause 6.18.5(b), Ergon Energy may not recover the expected revenue, tariffs will be adjusted in accordance with clause 6.18.5(c) of the NER, so as to ensure recovery of expected revenue with minimum distortion to efficient patterns of consumption.

As noted in Sections 6.3 and 6.8, Ergon Energy's charging parameters aim to effectively signal LRMC to customers, while recovering the remainder of regulated revenues in ways that seek to avoid distorting network usage decisions away from those based on LRMC signals. This means that to the extent that LRMC-based charges are not expected to fully recover Ergon Energy's total regulated revenues, the shortfall needs to be recovered in some other way. For practical purposes, one of the simplest and least distortionary ways to recover shortfall revenues is through a fixed charge that does not vary with day-to-day changes in customer behaviour.

As indicated in Section 2.2, Ergon Energy is planning to modify tariff parameters over time to improve the cost reflectivity and non-distortionary properties of our tariff structures. This is likely to mean capacity and demand charges will more fully reflect LRMC and volume charges will fall (in relative terms) while fixed charges will rise.

8.2 Adjustments to tariffs within a regulatory year

Clause 6.18.2(b)(5) of the NER requires that a Pricing Proposal set out the nature of any variation or adjustment to the tariff that could occur during the course of the regulatory year and the basis on which it could occur.

Variations or adjustments to tariffs will occur where an ICC, CAC or EG advises Ergon Energy that they intend to alter their demand or connection characteristics during 2015–16. In this case, Ergon Energy would recalculate the charging parameters of the tariff. New tariffs will be created for each ICC, CAC or EG that connects during 2015–16, in line with the methodology set out in this Pricing Proposal.

During 2015–16, Ergon Energy may also be required to calculate additional tariffs and/or prices for existing services which we have not provided prices for in this Pricing Proposal. This may occur because of a new customer connection, a price has not been established for a service legitimately included in the Preliminary Determination, or there are changes through the Substitute Determination which require amendment. Examples of this include:

- standardised rates for a customer who is seeking to connect to the Mount Isa network as a CAC
- an indicative quoted price for the provision of unmetered supplies.

Ergon Energy will seek approval from the AER to include a tariff and/or price at that time.

In circumstances where Ergon Energy makes changes to methodologies during a regulatory year, Ergon Energy will not recalculate the charging parameters of a tariff to give effect to the change. The tariff that has been calculated to apply to customers in accordance with methodologies in this Pricing Proposal will continue to be applied, unless Ergon Energy obtains approval from the AER to adjust the tariffs during the course of the regulatory year to reflect the new methodologies.

As noted in Section 2.1.2, the Preliminary Determination will be revoked and substituted by 31 October 2015. It will be applied as from 1 July 2015, with a 'true-up' applied to account for changes between the Preliminary Determination and the Substitute Determination. To the extent these true-up adjustments are material, Ergon Energy may pass through some or all of the true-up adjustments through adjusted tariffs from 1 January 2016. The decision to pass through the true-up adjustment through adjusted tariffs will be dependent on:

- the materiality of the true-up adjustment
- the ability for billing and metering systems to make relevant changes for the true-up adjustment
- consultation with the AER, the QCA and the relevant jurisdictional Minister(s).

There are no other variations or adjustments proposed to be made to remaining tariffs during the course of the next regulatory year.[43]

8.3 Changes between regulatory years

Clause 6.18.2(b)(8) of the NER requires that a Pricing Proposal must describe the nature and extent of change from the previous regulatory year and demonstrate that the changes comply with the NER and any applicable Distribution Determination.

8.3.1 Preliminary Determination

The Preliminary Determination contained a number of changes that impact pricing arrangements in the regulatory control period 2015–20. The main changes, which are described in more detail in the remainder of this section, relate to:

- the classification of services
- the allowed rate of return
- recovery of Solar Bonus Scheme amounts
- nominated cost pass through events.

A number of other changes were also made to the:

- formulae for Standard Control Services and Alternative Control Services. These changes are identified in other sections of the Pricing Proposal. However, being the first year of the regulatory control period, the Preliminary Determination sets a schedule of prices for many of the Alternative Control Services we provide.
- DUOS unders and overs account. The AER has removed the tolerance limits which applied in the regulatory control period 2010–15 and changed parts of the DUOS unders and overs account to reflect the Standard Control Services formula. Ergon Energy has applied these changes in Section 6.5.2.

Classification of services

Attachment 13 of the Preliminary Determination sets out the classification of distribution services for Ergon Energy in the regulatory control period 2015–20. There have been a number of changes since the previous regulatory control period. The following sections provide further detail on the implication of these changes for our Pricing Proposal.

[43] The exception being the maximum price caps under Schedule 8 of the *Electricity Regulation 2006* discussed in Section 4.6 of this Pricing Proposal.

Default Metering Services

The AER has reclassified Default Metering Services as an Alternative Control Service. This means the costs of providing these services will be recovered through charges levied directly on the customer requesting the service (rather than being recovered through DUOS charges that spread the costs across all customers).

As a consequence of this reclassification, Ergon Energy has made the following changes:

- created a new tariff class for Default Metering Services (refer to Table 7.1)
- introduced annual metering charges applied as cents/day charge and an upfront charge for new or upgraded meters, in accordance with section 16.2.1 of Attachment 16 of the Preliminary Determination (refer to Section 4.3)
- removed metering assets associated with Alternative Control Services from our DCOS Model and the avoidable and stand alone costs calculations. It is important to note we have retained some metering assets attributable to load control, as network related load control remains a Standard Control Service.

Public Lighting Services

Public Lighting Services (formerly ‘ACS – Street Lighting Services’) remain classified as an Alternative Control Service. However, we have revised the approach to developing charges. In the previous regulatory control period, these charges were determined based on geographic location (i.e. East, West or Mount Isa) and the type of light (i.e. Major or Minor). From 1 July 2015, they will be based on the type of light and the ownership basis (i.e. EO&O or G&EO).

The change in approach has resulted in new public lighting charges (refer to Appendix 4), as well as a reduction in the number of tariff classes (from three to one, refer to Table 7.1).

The AER has also classified emerging public lighting technology as an Alternative Control Service (previously not classified). This means the ARR for Public Lighting Services (on which our daily public lighting charges are based) also includes the costs of a LED transition program.

Additionally, Ergon Energy will now explicitly charge an exit fee when public lighting assets are withdrawn before the end of their normal functional life.[44]

Further information on these charges is contained in Section 4.4 above.

Embedded generators

From 1 July 2015, Ergon Energy will treat the connection of embedded generators that are larger than those classified as micro embedded generators under AS4777 as major customer connections. This is consistent with the AER’s classification of services.

This means embedded generators connecting to our network that are larger than 30 kVA will be required to pay upfront for their connection assets or will be required to construct the assets themselves and gift them to Ergon Energy. Previously, these customers formed part of our SAC network user group. As such, they would have only contributed to the cost of their connection to the extent it was ‘uneconomic’.

As a result of this reclassification, Ergon Energy has revised our SAC network user group definition to remove the reference to embedded generators with a capacity less than or equal to 1 MW (refer to Table 3.1).

[44] Outside of the LED transition program.

Other Alternative Control Services

In addition to the changes discussed above, the AER has made a number of other reclassifications. Table 8.1 sets out these changes and their implications in terms of the recovery of the costs of providing these services.

It should be noted that Ergon Energy has proposed a number of new fee based and quoted services, in accordance with the AER's classification of services. For example, we have introduced 'Carrying out planning studies and analysis relating to connection applications' as a quoted price service. A complete list of services offered in 2015–16 is contained in Appendix 4.

Table 8.1: Other changes in service classifications, 2015–20

Service	2010–15 classification	2015–20 classification	Implication of classification change
Carrying out planning studies and analysis relating to connection applications	Standard Control / Alternative Control	Alternative Control	For those components of these services that were previously classified as Standard Control Services, the change in classification means that the costs of providing these services will be recovered through charges levied directly on the customer requesting the service (rather than being recovered through DUOS charges that spread the cost across all customers). There will be no changes for those specific services that were already classified as Alternative Control Services.
Feasibility and concept scoping, including planning and design, for large customer connections	Standard Control / Alternative Control	Alternative Control	
Protection and Power Quality assessment – prior to connection and after connection	Standard Control / Alternative Control	Alternative Control	
Accreditation of alternative service providers and approval of their designs, works and materials	Standard Control / Alternative Control	Alternative Control	
Auxiliary metering services	Not currently classified / Standard Control / Alternative Control	Alternative Control	The change in classification allows Ergon Energy to explicitly recover AER-approved costs of providing these services from the customer who requests the service. There will be no changes for those specific services that were already classified as Alternative Control Services.
Commissioning and energisation of large customer connections	Standard Control	Alternative Control	The change in classification means that the costs of providing these services will be recovered through charges levied directly on the customer requesting the service (rather than being recovered through DUOS charges that spread the cost across all customers). For ROLR services, the customer is not necessarily an end-use customer and may be a retailer.
Real estate development connection	Standard Control	Alternative Control	
Removal of network constraint for embedded generator	Standard Control	Alternative Control	
Customer requests provision of electricity network data requiring customised investigation, analysis or technical input	Standard Control	Alternative Control	
Services provided in relation to a Retailer of Last Resort (ROLR) event	Standard Control	Alternative Control	
Tender process	Not currently classified	Alternative Control	The change in classification allows Ergon Energy to explicitly recover the costs of providing these services from the customer who
Witness testing	Not currently classified	Alternative Control	

Service	2010–15 classification	2015–20 classification	Implication of classification change
Customer build, own and operate consultation services	Not currently classified	Alternative Control	requests the service.
Emergency recoverable works	Alternative Control	Unclassified	The change in classification means the AER will have no regulatory oversight over these services in the regulatory control period 2015–20. This means Ergon Energy can determine the appropriate price for these services on a competitive basis.
High load escorts	Alternative Control (line lifting component) / Unclassified (route scoping component)	Unclassified	

Wasted truck visits

Ergon Energy has changed our approach to wasted truck visits, following advice from the AER that it is not a service.[45] A wasted truck visit is a service that is not able to be completed after the truck has left the depot (e.g. if a retailer/customer cancels a service order after the truck has left the depot but before the service order is completed). In the regulatory control period 2010–15, a wasted truck visit is classified as an Alternative Control Service.

From 1 July 2015, Ergon Energy will recover the costs of wasted attendance via the following mechanisms:

- for Standard Control Services, through the relevant “Prevented access” fee based services set out in Appendix 4
- for fee based services, through a “Call out fee – no service undertaken”. The call out fee will vary with the specific service requested (refer to Appendix 4)
- for quoted services, Ergon Energy will charge for the work performed in accordance with the quoted services formula.

Return on debt

Ergon Energy will apply the return on debt detailed in Attachment 3 of the Preliminary Determination in 2015–16. However, the return on debt for subsequent years of the regulatory control period will be updated annually under the trailing average approach. To give effect to this, the X factor in the PTRM will be revised in accordance with the formula specified in Attachment 3 of the Preliminary Determination.

This approach is different to the regulatory control period 2010–15, where the return on debt (and hence the WACC) was set in advance for the entire regulatory control period.

Jurisdictional scheme – Solar Bonus Scheme

The costs of the FiT payments made under the Queensland Government Solar Bonus Scheme were treated as operating expenditure in the regulatory control period 2010–15, with the differences between forecast FiT payments and actual FiT payments being a specific pass through event. Once the cost pass through amounts were approved, Ergon Energy adjusted our annual revenue allowances to pass through these amounts to customers in our DUOS charges.

In the regulatory control period 2015–20, these costs will be recovered as a jurisdictional scheme amount. This means they will not form part of the standard DUOS charges. The process of allocating and recovering jurisdictional scheme amounts is outlined in Section 6.13 above.

[45] AER (2014), *Final Framework and approach for Energex and Ergon Energy, Regulatory control period commencing 1 July 2015*, April 2014, p49.

Nominated pass through events

To ensure we are able to recover the legitimate costs of unpredictable and high cost events that are beyond our control, the NER includes a cost pass through mechanism. There are a number of cost pass through events prescribed under clause 6.6.1 of the NER ('prescribed events'). In addition, the AER has approved the following cost pass through events ('nominated events') to apply to Ergon Energy in the regulatory control period 2015–20:

- natural disaster event
- insurance cap event
- insurer's credit risk event.[46]

If a cost pass through event occurs during the period, and it materially increases or decreases our costs, Ergon Energy may apply to the AER to pass these costs or reductions onto customers. If approved, this adjustment will occur through the C_t component of the TAR formula in the relevant year.

There have been no adjustments made in 2015–16 for any of the prescribed or nominated events applying in the regulatory control period 2015–20.

It should be noted that Ergon Energy no longer has access to a general nominated pass through event. This event allowed Ergon Energy to lodge a cost pass through application in the regulatory control period 2010–15 for any material uncontrollable and unexpected event. Ergon Energy will also recover FiT payments, which were previously a specific pass through event, under the jurisdictional scheme arrangements (refer above).

8.3.2 Network Tariff Strategy

As noted in Section 2.2, Ergon Energy is proposing a number of changes to our network tariff structures from 1 July 2015 for our Standard Control Services. These changes are set out in Table 8.2 and described in more detail in the remainder of this section.

Table 8.2: Summary of network tariff changes in 2015–16

Network user group	Tariff changes
ICC	▪ Introduction of an excess reactive power charge (excess kVAr charge) ▪ Consolidation of pre and post 30 June 2010 tariff class distinctions into a combined single class (change to ICC, CAC and EG tariff classes)
CAC	▪ Change to the existing capacity charge and actual demand charge. The charging parameters will now be denominated in kVA rather than kW ▪ Consolidation of existing site-specific tariffs into four standard HV tariffs for each zone ▪ Application of SAC standard TUOS region pricing ▪ Introduction of customer specific 'connection units' to enable the standard tariffs ▪ Introduction of optional STOUD tariffs for each zone, differentiated by voltage level
SAC >100 MWh p.a.	▪ Introduction of an optional STOUD tariff for each zone ▪ Commence phasing out the Demand High Voltage tariffs
SAC <100 MWh p.a.	▪ Introduction of a business and residential optional STOUD tariff for each zone ▪ Equalisation of the peak and shoulder energy volume rates in the STOUE tariff
EG	▪ Embedded generators that are larger than those classified as micro embedded generators under AS4777 will be moved to this network user group. This will apply to all new and existing customers

[46] Refer to Attachment 15 of the Preliminary Determination.

Changes to ICC tariffs

The key change for ICC tariffs in 2015–16 is the introduction of an excess kVAr charge. This charge reinforces the price signal introduced by the kVA tariff in 2014–15, which encourages customers to improve power factor and reduce their usage of network capacity.

The ratio of real power (kW) to actual power (kVA) is known as the power factor. A customer's power factor and demand as measured in kVA is important because distribution systems must be designed to supply the actual power required. A low power factor means actual power delivered will be unnecessarily high.

The excess kVAr charge is applied against the kVAr used by a customer that exceeds what they would be entitled to use at their minimum compliant power factor at authorised demand.

The approach to the allocation of TUOS to individual customers has not changed.

The excess kVAr charge has been reflected in the tariff charging parameters for ICCs, as detailed in Appendix 2.

Changes to CAC tariffs

Charging on a kVA basis

Consistent with our changes to the ICC class in 2014–15, Ergon Energy is moving from a kW basis for the two demand-related charges (capacity and actual demand) to a kVA basis for the DUOS and TUOS components.

Our network charges are currently not signalling the network impact of a premises with low power factor. Our aim is to use kVA tariffs to give better pricing signals for our CACs (i.e. signals that reflect the additional capacity that we must supply to a customer associated with a lower power factor).

As per our existing ICC tariffs, the leading power factor has been discounted, with only the lagging power factor incorporated into the calculation of the kVA charges.

This change to kVA has been reflected in the tariff charging parameter demand denomination for CACs, as detailed in Appendix 1 and Appendix 2.

Minimising complexity through standardised CAC tariffs

Ergon Energy has reduced the number of CAC tariffs from 179 site-specific tariffs to four standard tariffs in each pricing zone. Maintaining site-specific tariffs for such a large number of customers is resource intensive; with little benefit to our customers. Adopting standard tariffs will result in greater market transparency, as the standard rates can be published. It also aligns more closely with approaches taken by other DNSPs.

In order to implement standardisation, the customer specific component relating to dedicated connection assets in the current fixed charge will be replaced with a standard daily fixed charge which is then applied against each customer's individual number of connection units.

For customers on our existing post 30 June 2010 tariffs and new customers, no connection units will apply. That is, only the standard rates will apply. For customers on pre 30 June 2010 tariffs, the connection unit will be three or greater. The connection unit value has been calculated in the following manner:

1. Unbundle the site-specific and standard DUOS fixed daily charge.
2. Subtract the allocation of connection assets, operating and maintenance, and administration associated with the standard charge from the site-specific.
3. Take the result and re-bundle as a DUOS fixed daily charge.

4. Divide the DUOS fixed daily charge by a constant to determine the number of connection units.
5. Number of connection units then set for each customer as the constant.
6. Sum the re-bundled DUOS fixed daily charge divided by the sum connection units to determine connection unit charge.

The fixed charge rate that applies to a particular customer is calculated by multiplying the standard daily fixed charge rate by the customer's specific number of connection units.

The proposed standardised CAC tariffs in each pricing zone are:

- CAC 22/11 kV Line
- CAC 22/11 kV Bus
- CAC 33 kV
- CAC 66 kV.

TUOS allocation has also changed. We have applied a similar approach to TUOS as that taken for our SAC network user group. Charges for each Bulk Supply Point are allocated to one of three geographical TUOS Regions, with TUOS charges calculated based on the combined totals. This means the current Common Service and General charge applying to CACs has been removed and will be incorporated in the Volume charge. Unlike SACs, the capacity charge for a customer's authorised demand will be used (i.e. not an actual charge based on Maximum Demand).

In order to be consistent with existing arrangements, CAC connections that are deemed by Ergon Energy to be a back-up supply will not have fixed daily TUOS charges applied to them. The authorised demand for back-up supplies will also be set to zero. This means TUOS charges will only apply where the actual demand and metered energy at the customer's installation is greater than zero in any month.

Finally, as a result of the standardisation, one customer will be reclassified into the ICC class. This is because their specific supply arrangements are not aligned with cost recovery through a standard CAC tariff.

The standardised tariffs and corresponding rates are included in Appendix 1. The confidential connection units applying to each CAC are contained in Appendix 2.

Offering greater choice with a STOUD tariff

Ergon Energy is offering an optional STOUD tariff to our CACs in 2015–16. The structure of this tariff is based on the SAC >100 MWh p.a. STOUD tariff (refer below), but it incorporates the AD component that exists in current CAC tariffs in determining the chargeable kVA quantity for the peak capacity charge. This has been achieved by integrating the AD component within the charging for STOUD tariff's capacity component.

The proposed STOUD tariffs for our CACs in each pricing zone are:

- Seasonal TOU Demand CAC 22/11 kV Line
- Seasonal TOU Demand CAC 22/11 kV Bus
- Seasonal TOU Demand CAC Higher Voltage (66/33 kV).

The connection unit mechanism described above will also be applied to the CAC STOUD tariffs.

The new STOUD tariffs and corresponding rates are included in are included in Appendix 1.

Changes to SAC >100 MWh p.a. tariffs

Introduction of optional STOUD tariff

The optional STOUD tariff is LRMC based and aims to provide transparency of when a customer's use of our network is most likely to contribute to additional investment in network augmentation. We are proposing to introduce a single STOUD tariff in each pricing zone. These tariffs will be available to SAC >100 MWh p.a. customers regardless of their supply voltage (high or low).

The seasonality and peak times are based on the work that underpinned the SAC <100 MWh p.a. STOUE tariff, with tariff design changes consistent with presenting the LRMC signal to customers through a peak demand charge rather than through a peak energy price. With respect to the LRMC recovery at peak time, the demand tariff combines the STOUE peak and shoulder periods and applies a single rate to the maximum demand in the combined period. A threshold demand mechanism is also applied to reduce impacts on small customers compared to the default tariffs.

Details of this tariff are provided in Appendix 1 and 2.

Phasing out of high voltage tariffs

Our existing SAC >100 MWh p.a. tariff options include four tariffs which customers can self-select from based on their size and supply voltage. The Demand High Voltage tariff is an optional tariff, with many high voltage customers currently choosing to use the low voltage tariffs (i.e. Demand Large, Demand Medium and Demand Small). The Demand High Voltage tariff is currently used by a small number of customers.

In 2015–16, a number of customers on the Demand High Voltage tariff in 2014–15 are expected to benefit from shifting to the low voltage and STOUD tariff options. It is our intention to remove the Demand High Voltage tariffs in the West and Mount Isa zones. The Demand High Voltage tariff will be retained in the East Zone. However, the tariff will be made obsolete and will only be available to existing customers currently using the tariff immediately prior to 1 July 2015.

Changes to SAC <100 MWh p.a. tariffs

Introduction of optional STOUD tariff

We are introducing an optional STOUD tariff in each pricing zone, different for residential and business customers.

The seasonality and peak times are based on the work that underpinned the SAC <100 MWh p.a. seasonal TOU energy tariff, with tariff design changes consistent with driving the LRMC signal predominantly through a peak demand charge rather than through a peak energy price. With respect to the LRMC recovery at peak time, the demand tariff combines the peak and shoulder periods and applies a single rate to the maximum demand in the combined period.

Details of this tariff are provided in Appendix 1 and Appendix 2.

Customer impacts

In developing these changes and the resulting tariffs presented in this Pricing Proposal, Ergon Energy has undertaken a considerable customer and stakeholder consultation process to ensure we understand and consider any customer or broader stakeholder implications. This included:

- promoting the consultation process in press advertising and other channels
- direct stakeholder notification of consultation papers and submission deadlines
- direct engagement with large customers (written and one-on-one)
- hosting several face-to-face consumer advocacy / interest group meetings

- updating our own Customer Council
- hosting three information webinars
- publishing our engagement documentation, and additional reference reports, on a dedicated web page
- developing an online network tariff comparator to show how moving usage to outside peak times could reduce a bill
- incorporation of some of the changes into material presented in the QCA's regional workshops
- other engagement with retailers, government and other stakeholders.

Further information on this process, including submissions received across our consultation process, is provided on our website.[47] In addition to customer and stakeholder input, we have performed our own detailed analysis and drawn upon external economic and tariff expertise.

The changes to tariff structures presented in this Pricing Proposal are revenue neutral. Changes within a fixed revenue constraint inevitably result in winners and losers – some customers benefitting from the changes and others being disadvantaged. Accordingly, in determining the extent of the shift in tariffs, Ergon Energy has carefully considered the customer impact on both the level and distributional impact of changes.

When setting 2015–16 tariffs we have taken into account outcomes from application of the combined DUOS and Jurisdictional Scheme charges on fixed daily charges.

After a number of years of increases in distribution prices, the Preliminary Determination results in a reduction in the revenue requirement for 2015–16 compared to the previous year. This reduction in DUOS charges has been incorporated into our tariffs.

Managing customer impacts for larger customers (consumption >100 MWh p.a.)

We have carefully considered the customer impacts of moving to excess kVAr charging for ICCs. Ergon Energy designed the initial excess kVAr charge on the basis of a monthly charge applied to kVAr supplied at the time of monthly maximum demand which was in excess of kVAr level at a compliant power factor.

Based on consultation and closer analysis of customer impacts we now propose to amend the framework of the excess kVAr charge to calculate a permissible kVAr level for a site based on a compliant power factor at the authorised demand.

It should be noted this structural change is 'revenue neutral' within the ICC network user group. The additional revenue recovery from the excess kVAr charge is being offset by an adjustment to the energy rate for all ICCs.

We also considered the following impacts for the CAC network user group:

- introducing a kVA basis of charging
- moving from an individual site-specific tariff to standardised rates
- the structure of the excess kVAr charge (if introduced in 2016–17).

Ergon Energy notes there is some redistribution of TUOS allocation between customers as a result of moving from site-specific TUOS charges to a general TUOS charge. This redistribution is generally offset by lower DUOS charges applying across the network user group.

We also analysed the customer impacts of different structures for the optional STOUD for CACs. Our decision to incorporate a minimum chargeable demand at different voltage levels, as well as the

[47] See https://www.ergon.com.au/network/network-management/network-pricing/network-tariff-strategy-consultation/2015-16-consultation-information.

application of Peak and Off-Peak charges, is defined to minimise, as far as possible, the impact for customers if they choose to adopt this new tariff.

The proposed CAC structural change is also revenue neutral.

Managing customer impacts for smaller customers (consumption <100 MWh p.a.)

Ergon Energy has been cognisant of the impact of the Preliminary Determination on DUOS charges. In particular we note there has been a reduction in the amount of revenue we must recover in respect of DUOS charges. However, this has been partially offset by the change in treatment of some costs from 1 July 2015:

- revenues associated with FiT payments are recovered by a separate charge rather than through DUOS charges
- revenues associated with Default Metering Services are recovered by a separate charge rather than through DUOS charges.

We have sought to ensure our fixed charges are reduced to offset some of the costs that will be incurred through these new charging parameters. This will ensure customers are not paying significantly more in daily fixed charges than what they were paying in 2014–15.

We have also been consulting with customers on the ‘costs of inaction’ in tariff reform. We noted that volume based tariffs can lead to inefficient consumption and investment behaviour. This not only increases the overall cost of supplying electricity, but also increases cross subsidies between customers. The level of cross subsidisation is exaggerated when customers actively invest to reduce their bills, while others either choose not to, or worse still, cannot invest.[48]

Our decisions on the levels of tariff component, as well as our proposal to introduce new tariffs, take these impacts into account.

8.3.3 Other changes compared to 2014–15 Pricing Proposal

In addition to the above changes, Ergon Energy has made a number of amendments to this Pricing Proposal. These include:

- consolidating the pre and post 30 June 2010 tariff classes for our major customers (refer to Section 6.1). This has had flow on effects to the presentation of our forecast weighted average revenue (Appendix 3) and the calculation of avoidable and stand alone costs (Appendix 2). There has been no impact on tariffs or the aggregated revenue we expect to recover from customers. In accordance with our reassignment procedures outlined in Section 6.2, Ergon Energy will notify affected customers’ retailers of the change in tariff class. This notification will occur once AER approval of the Pricing Proposal is received.
- amending our approach to LRMC in the setting of rates to apply to the new tariff structure parameters and rebalancing of existing parameters (refer to Section 6.8)
- considering the impact on transaction costs (refer to Section 6.9)
- considering the likelihood and ability of customers to respond to price signals (refer to Section 6.10)
- explicit consideration of churn from legacy tariffs to the new LRMC based tariffs (refer to Section 8.4).

[48] https://www.ergon.com.au/__data/assets/pdf_file/0018/250515/Consultation-Paper-The-Case-for-Demand-Based-Tariffs..pdf.

8.3.4 Compliance with regulatory obligations

Ergon Energy has demonstrated that the changes discussed in Section 8.3 comply with the NER and any applicable Preliminary Determination throughout this Pricing Proposal. A summary of our compliance with these obligations is set out in Table 5.1 and Table 5.2.

8.4 Forecasting methodology

Clause 6.18.8(a)(2) of the NER requires that the AER must approve the Pricing Proposal if it is satisfied that all forecasts associated with the proposal are reasonable.

This section demonstrates how Ergon Energy considers that the forecasts used for pricing purposes are reasonable, having specific regard for the development of energy consumption, energy demand, customer numbers, customer churn and TUOS payment forecasts.

Ergon Energy annually prepares a one year forecast of customer numbers and energy consumption for preparation of our Pricing Proposal. These forecasts are prepared in two phases, with the first phase generally prepared in October of each year to provide an initial forecast, and the second phase typically conducted in February and March of each year to refine the forecasts based on the most up to date information available prior to preparation of the annual Pricing Proposal. In conjunction with this process, individual energy consumption and demands for ICCs, CACs and EGs are also reviewed.

Both forecast phases have been completed and the refined forecasts used for developing the prices are set out in Appendix 2 of this Pricing Proposal.

The methodology used to forecast customer numbers, energy consumption and load for the purposes of developing the tariffs set out in this Pricing Proposal is the same as that used by Ergon Energy throughout the previous regulatory control period 2010–15. However, we are aware this approach has over the last few years resulted in forecast energy consistently higher than what is subsequently realised. This volume shortfall has in turn contributed to revenue under-recovery leading to increased revenue recovery requirements and price increases in subsequent years.

There are also significant uncertainties with regard to future revenue requirements and volumes. The AER will make a Substitute Determination in October this year. We also have uncertainties regarding commodity prices which may impact economic conditions. Finally, state government initiatives may increase the uptake of renewable energy. We have attempted to take these circumstances into account when forecasting energy in 2015–16.

For our SACs <100 MWh p.a., forecasts were prepared of the amount of energy that would be consumed in each IBT block for residential and business customers, and also of energy that would be consumed in each TOU pricing segment (i.e. Peak, Shoulder and Off-Peak).

For our STOUD tariffs, forecasts were prepared of the amount of energy that would be consumed in each TOU pricing segment (i.e. Peak, Shoulder and Off-Peak). We also forecast the expected revenue to be recovered from demand based on the profiles of a sample of customers.

As most customers will have the option of accessing a TOU variant tariff, and the net outcome would have different overall revenue implications, a forecast of the adoption of each tariff was required. Ergon Energy's forecasts are contained in Appendix 2. Ergon Energy has assumed there will be relatively low levels of customer churn, given:

- network experience in other jurisdictions suggests there is inertia in switching to TOU tariffs (even where there are significant price benefits)
- there are long lead times associated with customer response and change
- barriers associated with metering costs.

Ergon Energy's Regulatory Determination and Pricing section undertakes its projection of energy throughput based on the network user groupings (i.e. ICC, CAC, SAC and EG). The forecast for EGs is the amount of energy generated into Ergon Energy's distribution system. For all other customer groups, it is energy consumption that is being forecast.

The annual projections for energy for all customer groups are based on extrapolations of historical data, with adjustments made for known additions, trends and losses of load. However, we have taken into consideration factors identified above when setting forecasts for 2015–16.

The projected load for ICC, CAC and EG customers who have Connection and Access Agreements is based on their contracted demand. If no agreement is in place, their forecast demand is based on extrapolations of historical demand data, with adjustments made for known additions and losses of load. Similarly, the demand at each Transmission Connection Point is forecast and provided to Powerlink for use in the setting of their TUOS prices. Demand is not measured or forecast for the SAC customer grouping but sub-group demands are calculated using appropriate load factors which are then used as allocators in the Pricing Model.

Annual TUOS payments are made to Powerlink, other DNSPs, and EGs for Avoided TUOS. The forecast of annual TUOS payments to Powerlink is based on TUOS prices provided by Powerlink in April 2015. Forecast energy, historical energy and nominated demand are applied to the TUOS prices to give forecast TUOS payments for each Transmission Connection Point. Similarly, forecast TUOS payments to other DNSPs are based on rates provided by the DNSP and forecast energy and demand applicable to that supply. Forecast Avoided TUOS payments are based on the relevant EG's forecast export used within the Ergon Energy distribution network and the relevant transmission locational energy charge.

Appendix 1: Table of network tariffs for Standard Control Services

This appendix sets out the 2015–16 Standard Control Service network tariffs for:

- SACs
- CACs (excluding individual connection units).

Site-specific network tariffs for ICCs and EGs, as well as the specific connection units applying to each CAC, are provided in Appendix 2.

This appendix meets the following requirements of the NER:

- clause 6.18.2(b)(2) which requires Ergon Energy to set out the proposed tariffs for each tariff class
- clause 6.18.2(b)(3) which requires Ergon Energy to set out, for each proposed tariff, the charging parameters and the elements of service to which each charging parameter relates
- clause 6.18.9(a)(2) which requires Ergon Energy to maintain on our website for each tariff, the charging parameters and the elements of the service to which each charging parameter relates.

Appendix 2: Standard Control Services pricing model

This confidential model provides the following information for the AER's consideration:

- calculation of the unders and overs accounts for DUOS and TUOS
- the network tariff rates for 2015–16 and associated revenues and reconciliation
- our energy, load and customer number forecasts
- demonstration of how Ergon Energy meets the tests for avoidable and stand alone costs under clause 6.18.5 of the NER.

Appendix 3: Forecast weighted average revenue

This appendix sets out the forecast weighted average revenue for each Standard Control Service tariff class.

Table A3.1: Weighted average revenue (GST Exclusive)[49]

Tariff class	2014-15	2015-16
Individually Calculated Customer – East	$49,490,472	$42,037,078
Individually Calculated Customer – West	$19,017,137	$14,532,459
Individually Calculated Customer – Mount Isa	$0	$0
Connection Asset Customer – East	$101,440,035	$83,705,894
Connection Asset Customer – West	$12,645,084	$11,107,977
Connection Asset Customer – Mount Isa	$0	$0
Embedded Generation – East	$4,097,529	$2,860,317
Embedded Generation – West	$360,741	$238,471
Embedded Generation – Mount Isa	$0	$0
Standard Asset Customer – Large (>100 MWh p.a.) – East	$333,551,510	$305,940,529
Standard Asset Customer – Large (>100 MWh p.a.) – West	$91,912,766	$83,355,733
Standard Asset Customer – Large (>100 MWh p.a.) – Mount Isa	$4,653,615	$4,370,693
Standard Asset Customer – Small (<100 MWh p.a.) – East	$888,146,372	$667,097,974
Standard Asset Customer – Small (<100 MWh p.a.) – West	$242,699,158	$202,473,795
Standard Asset Customer – Small (<100 MWh p.a.) – Mount Isa	$13,288,190	$10,306,850
Standard Asset Customer – Unmetered – East	$16,095,841	$13,722,328
Standard Asset Customer – Unmetered – West	$2,181,413	$2,023,059
Standard Asset Customer – Unmetered – Mount Isa	$309,633	$300,718

49 While Ergon Energy has made changes within our tariff classes, we expect to recover the same amount of revenue from each tariff class under the new network tariff structures as we would have if the 2014–15 structures had remained in place.

Appendix 4: Alternative Control Services tariffs

This appendix sets out the tariffs applicable to Alternative Control Services in 2015–16.

All prices in this appendix are GST Exclusive.

Fee based services

Table A4.1: Fee based services prices

Service	2015-16 GST Exclusive	
	Total price (service undertaken)	Call out fee (no service undertaken)
Application fee - Basic or standard connection	$852.23	$0.00
Application fee - Basic or standard connection - Micro-embedded generators	$46.63	$0.00
Application fee - Basic or standard connection - Micro-embedded generators - Technical assessment required	$211.71	$0.00
Application fee - Real estate development connection	$892.30	$0.00
Protection and Power Quality assessment prior to connection	$1,320.64	$0.00
Temporary connection, not in permanent position - single phase metered - urban/short rural feeders	$561.13	$112.23
Temporary connection, not in permanent position - single phase metered - long rural/isolated feeders	$897.80	$448.90
Temporary connection, not in permanent position - multi phase metered - urban/short rural feeders	$561.13	$112.23
Temporary connection, not in permanent position - multi phase metered - long rural/isolated feeders	$897.80	$448.90
Supply abolishment during business - urban/short rural feeders	$336.68	$112.23
Supply abolishment during business hours - long rural/isolated feeders	$673.35	$448.90
De-energisation during business hours - urban/short rural feeders	$94.03	$37.39
De-energisation during business hours - long rural/isolated feeders	$561.13	$448.90
Re-energisation during business hours - urban/short rural feeders	$74.77	$37.39
Re-energisation during business hours - long rural/isolated feeders	$522.97	$448.90
Re-energisation during business hours - after de-energisation for debt - urban/short rural feeders	$74.77	$37.39
Re-energisation during business hours - after de-energisation for debt - long rural/isolated feeders	$522.97	$448.90
Accreditation of alternative service providers - real estate developments	$866.67	$0.00
Prevented access - one person crew - urban/short rural feeders	$52.43	N/A
Prevented access - one person crew - long rural/isolated feeders	$209.74	N/A
Prevented access - two person crew - urban/short rural feeders	$108.01	N/A
Prevented access - two person crew - long rural/isolated feeders	$432.06	N/A

Quoted services

It is important to note that the prices set out below are examples of potential prices for our quoted services. This is because the actual prices for quoted services will be determined at the time of the customer's enquiry and will reflect the actual requirements of the service.

Further, where Ergon Energy attends a premises to perform a service and is unable to complete the work order for reasons outside our control, such as a locked gate, we will charge a call out fee. The call out fee will reflect the opportunity cost of the fleet and labour resources.

Table A4.2: Potential quoted services prices

Service	2015-16 GST Exclusive
Application fee - Negotiated connection	$1,059.97
Application fee - Negotiated connection - Micro-embedded generators	$470.04
Application fee - Negotiated - Major customer connection	$6,697.26
Carrying out planning studies and analysis relating to connection applications	$2,115.46
Feasibility and concept scoping, including planning and design, for major customer connections	$17,013.36
Tender process	$9,904.79
Pre-connection site inspection	$1,228.06
Provision of site-specific connection information and advice for small or major customer connections	$724.35
Preparation of preliminary designs and planning reports for major customer connections, including project scopes and estimates	$8,914.32
Customer build, own and operate consultation services	$70,604.68
Detailed enquiry response fee - EGs 5MW & above	$23,601.41
Design and construction of connection assets for major customers	$8,257,344.71
Commissioning and energisation of major customer connections	$40,773.26
Design and construction for real estate developments	$155,815.51
Commissioning and energisation of real estate development connections	$6,247.03
Removal of network constraint for embedded generator	$511,004.45
Move point of attachment - single/multi phase	$3,456.45
Re-arrange connection assets at customer's request	$62,316.50
Protection and Power Quality assessment after connection	$2,638.16
Temporary de-energisation - no dismantling	$700.50
LV Service line drop and replace - physical dismantling	$1,016.35
HV Service line drop and replace	$4,193.56
Supply enhancement	$1,198.14
Provision of connection services above minimum requirements	$279,089.44
Upgrade from overhead to underground service	$8,060.66
Rectification of illegal connections or damage to overhead or underground service cables	$203.52
De-energisation after business hours	$135.88
Re-energisation after business hours	$108.05
Accreditation of alternative service providers - major customer connections	$5,992.11
Approval of third party design - major customer connections	$13,206.39
Approval of third party design - real estate developments	$188.20
Construction audit - major customer connections	$85,701.96

Service	2015-16 GST Exclusive
Construction audit - real estate developments	$1,091.42
Approval of third party materials	$17,755.06
Special meter read	$118.85
Meter test	$420.61
Meter inspection and investigation on request	$271.36
Metering alteration	$2,682.88
Exchange meter	$271.36
Type 5 to 7 non-standard metering services	$384.49
Removal of a meter (Type 5 & 6)	$127.78
Meter re-seal	$549.50
Install additional metering	$271.36
Change time switch	$203.52
Change tariff	$210.30
Reprogram card meters	$1,221.12
Install metering related load control	$271.36
Removal of load control device	$271.36
Change load control relay channel	$135.68
Services provided in relation to a Retailer of Last Resort (ROLR) event	$2,680.38
Non-standard network data requests	$660.32
Provision of services for approved unmetered supplies	Not offered
Customer requested appointments	$706.08
Removal/rearrangement of network assets	$288,540.82
Aerial markers	$686.42
Tiger tails	$2,308.68
Assessment of parallel generator applications	$1,650.80
Witness testing	$3,643.88
Removal/rearrangement of public lighting assets	$19,679.42

Default Metering Services

Table A4.3: Annual metering charges

Tariff class	Costs	2015-16 Fixed charge ($ p.a.) GST Exclusive
Primary	Non–capital	$24.44
	Capital	$6.49
Controlled load	Non–capital	$8.99
	Capital	$2.39
Solar	Non–capital	$6.08
	Capital	$1.61

Table A4.4: Metering upfront capital charges

Meter	2015-16 Fixed charge ($/meter) GST Exclusive
Single phase	$401.28
Dual element	$452.25
Three phase	$492.29

Public Lighting Services

Table A4.5: Daily Public Lighting Services prices

Public Lighting Services	2015-16 Fixed charge ($/day/light) GST Exclusive
EO&O - Major	$1.0252
EO&O - Minor	$0.6108
G&EO - Major	$0.4140
G&EO - Minor	$0.2712

Table A4.6: Public Lighting Services exit fees

Public Lighting Services - exit fees	2015-16 ($/light) GST Exclusive
EO&O - Major - Exit fee	$1,414
EO&O - Minor - Exit fee	$854
G&EO - Major - Exit fee	$234
G&EO - Minor - Exit fee	$198

Appendix 5: Alternative Control Services pricing models

These confidential models provide quantitative information to demonstrate the calculation of our fee based and quoted services, public lighting exit fees and upfront capital charges for metering.

Appendix 6: Expected price trends

This appendix sets out indicative prices for our Standard and Alternative Control Services for the remainder of the regulatory control period 2015–20.

Indicative prices will be recalculated each year. All prices in this appendix are GST Exclusive.

Glossary

Abbreviations

ABS	Australian Bureau of Statistics
ACS	Alternative Control Services
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARR	Annual Revenue Requirement
ATMD	Any Time Maximum Demand
BCS	Benchmark cost of supply
CAC	Connection Asset Customer
CAM	Cost Allocation Method
Capex	Capital expenditure
CPI	Consumer Price Index
DCOS	Distribution Cost of Supply
DNSP	Distribution Network Service Provider
DUOS	Distribution Use of System
EDNC	Electricity Distribution Network Code
EEQ	Ergon Energy Queensland Pty Ltd
EG	Embedded Generator
Ergon Energy	Ergon Energy Corporation Limited
Excess kVAr	Excess reactive power charge
GWh	Gigawatt hour
IBT	Inclining Block Tariff
ICC	Individually Calculated Customer
kV	Kilovolt
kVA	Kilovolt-ampere
kVAr	Kilovolt-ampere reactive
kW	Kilowatt
kWh	Kilowatt hour
Law	National Electricity Law
LOB	Line of Business
LRIC	Long Run Incremental Cost
LRMC	Long Run Marginal Cost
MWh	Megawatt hour
NEM	National Electricity Market
NER	National Electricity Rules
NMI	National Metering Identifier
Opex	Operating expenditure
p.a.	Per annum

POA	Price on application
PTRM	Post Tax Revenue Model
PV	Photovoltaic
RIN	Regulatory Information Notice
ROA	Return on assets
SAC	Standard Asset Customer
SCS	Standard Control Services
SPARQ	SPARQ Solutions Pty Ltd
STOUD	Seasonal Time-of-Use Demand
STOUE	Seasonal Time-of-Use Energy
STPIS	Service Target Performance Incentive Scheme
TAR	Total Annual Revenue
TNSP	Transmission Network Service Provider
TOU	Time-of-Use
TSS	Tariff Structure Statement
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital

Definitions

Actual demand charge	A type of charge (charging parameter) included in Ergon Energy's network tariff structures to signal the effect demand has on the shared network and system augmentation. The demand used in the calculation of the charge is the maximum demand recorded in any half hour period each month.
Alternative Control Service	A distribution service provided by Ergon Energy that the AER has classified as an Alternative Control Service under the NER. Includes fee based services, quoted services, Public Lighting Services and Default Metering Services.
Annual revenue adjustment	Annual adjustments made to Ergon Energy's smoothed revenue requirement for Standard Control Services revenue for matters such as out-turn inflation, allowed rate of return, STPIS, pass throughs, and the difference between forecast and actual revenue received for DUOS charges, capital contributions and shared assets.
Annual Revenue Requirement (ARR)	The revenue determined by the applicable PTRM.
Any time energy	Is the amount of energy consumed by the customer irrespective of the time of day.
Any Time Maximum Demand (ATMD)	Is the maximum half hourly demand for a customer that occurs at any time within a specified period.
Australian Energy Market Commission (AEMC)	The AEMC is the rule maker and developer for Australian energy markets. As a national, independent body they make and amend the detailed rules for the NEM and elements of natural gas markets.

Australian Energy Regulator (AER)	The AER is an independent statutory authority that is part of the Australian Competition and Consumer Commission. The AER is responsible for the economic regulation of electricity networks in the NEM. It also monitors the wholesale electricity and gas markets and is responsible for compliance with and enforcement of the National Electricity Law and Rules, National Gas Law and Rules, and the National Energy Retail Law and Rules.
Avoided TUOS	The amount paid to an eligible EG for the locational component of prescribed TUOS services that would have been payable by Ergon Energy to a TNSP had the EG not been connected to the distribution network. The methodology Ergon Energy uses to comply with the NER is set out in the *Information Guide for Standard Control Services Pricing*.
Business customer	Means a customer who is not a residential customer (as defined in the Queensland Electricity Industry Code[50]).
Capacity charge	A type of charge (charging parameter) included in Ergon Energy network tariff structures. The capacity charge is reflective of the costs associated with the network capacity required by a customer on a long term basis. It is similar to the actual demand charge, but more effectively takes into account the impact low load factor customers have on system augmentation. The demand used for the calculation of the charge is the authorised demand, or if no authorised demand, an annual maximum demand.
Capital contribution	A capital contribution is a prepayment for the provision of direct control services. A capital contribution may be charged to a customer if the new connection or modification for an existing connection is required to the network to accommodate the connection/modification. Ergon Energy's Connection Policy sets out circumstances in which a capital contribution may be required and details how the capital contribution to be charged to a customer is calculated.
Charging parameter	The constituent elements of a tariff (as defined in the NER).
Connection	The physical link to or through a transmission network or distribution network.
Connection Asset Customer (CAC)	Means a customer classified as a CAC in accordance with the definition in our Pricing Proposal. Typically reflects those customers with required capacity above 1,500 kVA, or with electricity consumption greater than 4 GWh (but less than 40 GWh) per year.
Connection assets	Those components of a transmission or distribution system which are used to provide connection services. Connection assets are those assets required to connect an electrical installation to the shared network and are all the assets from the connection point back up to and including the network coupling point.
Connection point	The agreed point of supply established between Network Service Provider(s) and another Registered Participant, Non-Registered Customer or franchise customer.

[50] Note: This will be replaced with the Electricity Distribution Network Code (EDNC) on 1 July 2015.

Customer	A person or entity that receives, or wants to receive a supply of electricity for a premises, or any other distribution service from Ergon Energy.
Dedicated connection assets	Assets that are dedicated to a network user of any size. In most circumstances these are ‘connection assets’. This is because no other party is using the assets and it enables the user to pay for exactly the capacity and style of assets they seek to have. In some cases, dedicated connection assets may later be shared with another customer in which case the network coupling point is moved further downstream.
Default Metering Services	A type of Alternative Control Service. Relates to the installation, provision, maintenance, reading and data services of basic electricity meters (Type 5 and 6) for small to medium business and residential customers. Ergon Energy recovers our costs in providing Default Metering Services through daily metering charges which we bill to retailers and an upfront charge for new or upgraded meters.
Demand	The amount of electricity energy being consumed at a given time measured in either watts (W) or volt amperes (VA). The difference between the two is the power factor.
Direct control service	Distribution services subject to economic regulation by the AER under the NER. Direct control services are further subdivided into Standard Control Services and Alternative Control Services.
Distribution Cost of Supply (DCOS) Model	The Ergon Energy model used to allocate costs to network users and convert the revenue cap and transmission related costs (or designated pricing proposal charges) into network tariffs.
Distribution network	The electrical system used to transport electricity from the high voltage transmission network connection point to distribution network users.
Distribution Use of System (DUOS) charge	Component of the network tariffs which covers costs associated with connection services and/or use of the distribution network for the conveyance of electricity (i.e. Standard Control Services).
East Zone	Those areas where the network users are supplied from the distribution system connection to the national grid and have a relatively low distribution cost to supply. The local government areas covered by the East Zone are located in the *Information Guide for Standard Control Services*.
Electricity Market	Means the National Electricity Market (NEM) as administered by the Australian Energy Market Operator.
Embedded Generator (EG)	Means a network user classified as an EG in accordance with the definition in our Pricing Proposal. EGs are those network users that export energy into the distribution system, except for micro embedded generators that have been classified as a SAC (such as small scale PV generators).
Energy	The amount of electricity consumed by a consumer (or all customers) over a period of time. Energy is measured in terms of watt hours (Wh), kilowatt hours (kWh), megawatt hours (MWh) or gigawatt hours (GWh).
Excess reactive power charge (Excess kVAr)	Charge applied against the kVAr used by a customer that exceeds what they would be entitled to use at their minimum compliant power factor at authorised demand.

Fee based services	A type of Alternative Control Service which Ergon Energy undertakes at the request of an identifiable customer, retailer or appropriate third party which is in addition to our Standard Control Services and is levied as a separate charge. The costs of providing the service (and therefore price) can be assessed in advance of the service being requested by a customer or retailer.
Preliminary Determination	The AER's Preliminary Determination sets the revenue and pricing control regime that Ergon Energy must comply with for the first year of the current regulatory control period (i.e. 2015–16).
Fixed charge	A type of charge (charging parameter) included in Ergon Energy network tariffs which is levied on a fixed dollar amount per day.
Gigawatt hour (GWh)	1,000,000 kilowatt hours.
High Voltage (HV)	Refers to parts of the network that are 11 kV or above.
Inclining Block Tariff (IBT)	A type of network tariff where the price per kWh increases as consumption thresholds are crossed during a particular time period.
Individually Calculated Customer (ICC)	Means a customer classified as an ICC in accordance with the definition in our Pricing Proposal. Typically reflects those customers with electricity consumption greater than 40 GWh per year, or where a customer's circumstances and connection arrangement mean that average prices are meaningless or inappropriate (e.g. only two or three customers in a supply system, or the customer is connected close to a Transmission Connection Point).
Isolated generation	Those areas supplied from Ergon Energy's isolated generation assets, except for the Mount Isa system. Includes communities in Western Queensland, the Gulf of Carpentaria, Cape York, various Torres Strait Islands, Palm Island and Mornington Islands. These areas are not subject to economic regulation by the AER, but are regulated by the Queensland Government.
Jurisdictional scheme amount	In respect of a jurisdictional scheme, the amounts a DNSP is required under the jurisdictional scheme obligations to: (a) pay to a person (b) pay into a fund established under an Act of a participating jurisdiction (c) credit against charges payable by a person, or (d) reimburse a person, less any amounts recovered by the DNSP from any person in respect of those amounts other than under the NER (as defined in the NER).
kVA	1,000 Volt-Ampere which is a measure of the apparent power flow which is a measure of the total capacity required to supply a customer's load.
kVAr	1,000 Volt-Ampere reactive which is a measure of reactive power. The excess kVAr charge is applied against kVAr drawn from the network that exceeds the minimum compliant power factor level.
kW	1,000 Watts which is a measure of the real component of power being consumed by the consumer's load.

Load factor	Measure of the percentage of time a load is used in any given period. Loads used 24 hours per day, 7 days a week have a load factor of 1 or 100 per cent.
Low Voltage (LV)	Refers to the sub 11 kV network.
Major customer	Are Individually Calculated Customers (ICCs), Connection Asset Customers (CACs) or Embedded Generators (EGs).
Major Customer Connection arrangements	Refers to the arrangements applying from 1 July 2010, where new or augmented connection assets are paid for or contributed by the major customer (i.e. not included in the network tariff).
Major Customer Connection service	Is a type of quoted price service which relates to the design and construction of connection assets for major customers.
Maximum demand	The maximum demand recorded at a customer's individual meter or the maximum demand placed on the electrical distribution network system at any time or at a specific time or within a specific time period, such as a month. Maximum demand is an indication of the capacity required for a customer's connection or the electrical distribution network.
Megawatt hour (MWh)	1,000 kilowatt hours
Mount Isa Zone	Those areas supplied from the isolated Mount Isa system. This zone is not connected to the national grid and would normally be excluded from the application of the NER. However, under the *Electricity – National Scheme (Queensland) Act 1997,* the Queensland Government has transferred responsibility for the economic regulation of the Mount Isa-Cloncurry supply network to the AER. The local government areas covered by the Mount Isa Zone are located in the *Information Guide for Standard Control Services*.
National Electricity Market (NEM)	The interconnected electricity grid covering Queensland, New South Wales, Victoria, Tasmania, South Australia and the Australian Capital Territory.
National Electricity Rules (NER)	Rules made under the National Electricity Law which govern the operation of the NEM.
National Metering Identifier (NMI)	A unique number assigned to each metering installation.
Network capacity	The maximum demand (kW) that the distribution network can provide for at any one time.
Network coupling point	The point at which connection assets join a distribution network, used to identify the distribution service price payable by a connection customer.
Network tariff	Refers to the price (or tariff) that Ergon Energy sets to recover costs associated with the customer's connection and use of the distribution and transmission network. Network tariffs comprise DUOS and TUOS components.
Network user	There are four network user groups included in Ergon Energy's network tariff structures – Individually Calculated Customers (ICCs), Connection Asset Customers (CACs), Standard Asset Customers (SACs) and Embedded Generators (EGs). For the purposes of our network pricing documents, the term 'network user' refers to both a 'customer' and an 'EG'.
Power factor	The ratio of kW to kVA at a metering point during a defined period.

Premises	Means premises owned or occupied by the customer.
Public Lighting Services	A type of Alternative Control Service. Relates to the provision, construction and maintenance of public lighting assets owned by Ergon Energy, and emerging public lighting technology. Ergon Energy recovers our costs in providing this service through a daily public lighting charge which we bill to retailers. We will also charge an exit fee, when public lights are scrapped before the end of their useful lives (outside of the LED program).
Public lights – Major	Standard major public lights are 100, 150, 250 and 400 watt High Pressure Sodium vapour lights and include any other non-standard or obsolete public lights that would be replaced with any of the above lights.
Public lights – Minor	Standard minor public lights are 50, 80 and 125 watt Mercury Vapour and some 70 and 100 watt High Pressure Sodium vapour lights (special locations only) and include any other non-standard or obsolete public lights that would be replaced with any of the above lights.
Quoted services	A type of Alternative Control Service. Similar to fee based services, but they are priced on application as the nature and scope of these services is variable and the cost (and therefore price) is specific to the individual retailer's or customer's needs.
Regulatory control period	The regulatory control period is a five (5) year period set down by the AER. The current regulatory control period is 2015–16 to 2019–20.
Regulatory year	Is a specific financial year within a regulatory control period.
Residential customer	Means a customer who acquires electricity for domestic use (as defined in the Queensland Electricity Industry Code[51]).
Revenue cap	The TAR plus any unders or overs adjustment needed to move the balance of the DUOS unders and overs account to zero.
Side constraint	Refers to the percentage by which the expected weighted average revenue to be raised from a Standard Control Service tariff class is allowed to increase by between regulatory years. Side constraints are intended to set a limit (or constraint) on the level of distribution price increase to be experienced by customers from one year to the next within a regulatory control period.
Standard Asset Customer (SAC)	Means a customer classified as a SAC in accordance with the definition in our Pricing Proposal. Typically reflects those customers with annual electricity consumption below 4 GWh per year. Includes customers with micro generation facilities (such as small scale PV generators) that have an exporting capability and an inverter capacity as per AS4777.
Standard Control Service	A distribution service provided by Ergon Energy that the AER has classified as a Standard Control Service under the NER. Includes network services, some connection services (including small customer connections) and Type 7 metering services. Ergon Energy recovers our costs in providing Standard Control Services through the DUOS component of network tariffs which are billed to retailers.

51 Note: This will be replaced with the EDNC on 1 July 2015.

Substitute Determination	The AER's Substitute Determination will revoke and substitute the Preliminary Determination. It will set the revenue and pricing control regime that Ergon Energy must comply with for the current regulatory control period, as well as any 'true-up' adjustments required to affect any changes between the Preliminary and Substitute Determinations.
Summer	The months of December, January and February.
Tariff class	A class of customers for one or more direct control services who are subject to a particular tariff or particular tariffs (as defined in the NER).
Threshold demand	The amount by which a SAC >100 MWh p.a. customer's metered monthly actual kW maximum demand is adjusted for the purposes of calculating the demand component of their network tariff. The actual demand charge tariff charging parameter ($/kW/month) is applied to the higher of metered monthly demand less the applicable threshold, or zero.
Time-of-Use (TOU)	A type of network tariff where the price per kWh varies according to when the consumption occurs. The TOU tariff may apply a different price during Peak, Shoulder and Off-Peak periods.
Transmission Use of System (TUOS) charge	Component of the network tariff which passes through costs associated with use of the transmission network. This includes designated pricing proposal charges as defined under the NER plus charges levied on Ergon Energy in relation to Chumvale and non-regulated Powerlink connection points.
Unmetered	A customer who takes supply where no meter is installed at the connection point.
Volume charge	A type of charge (charging parameter) included in Ergon Energy network tariffs which in part recovers costs that have been allocated on a postage stamped basis. The volume charge is calculated using the customer's metered energy (kWh) consumption and may be based on a flat rate, an inclining block or TOU charging structure (depending on the customer's applicable network tariff).
West Zone	Those areas outside the East Zone and connected to the national grid, which have a significantly higher distribution cost of supply than the East Zone. The local government areas covered by the West Zone are located in the *Information Guide for Standard Control Services*.

Contact information

Manager Regulatory Determination and Pricing
Ergon Energy Corporation Limited
PO Box 264
FORTITUDE VALLEY QLD 4006
Telephone: **13 74 66**
Email: netprice@ergon.com.au

Ergon Energy Corporation Limited ABN 50 087 646 062
Ergon Energy Queensland Pty Ltd ABN 11 121 177 802

ergon.com.au