2014–15 Pricing Proposal

Distribution services for 1 July 2014 to 30 June 2015

30 April 2014

Version 1.0 for AER approval

Revision history

Version	Date	Summary of changes
1.0	30 April 2014	Initial proposal to the AER for 2014–15.

Contents

1 Introduction

1.1 Background

Ergon Energy Corporation Limited (Ergon Energy) is a Distribution Network Service Provider (DNSP) to over 700,000 customers in regional Queensland. Our service area covers around 97 per cent of Queensland and has approximately 150,000 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)(2) of the National Electricity Rules (NER) requires Ergon Energy to submit a Pricing Proposal to the Australian Energy Regulator (AER) at least two months before the commencement of the regulatory year.

This Pricing Proposal sets out how Ergon Energy's proposed tariffs and prices in 2014–15 meet the requirements of the NER for both our Standard and Alternative Control Services.

Standard Control Services are core network, connection and metering services associated with the access and supply of electricity to customers. Ergon Energy recovers our costs in providing Standard Control Services through network tariffs which are billed to retailers.

Alternative Control Services are comprised of:

- *Fee Based Services* – regulated distribution activities which Ergon Energy undertakes at the request of an identifiable customer, retailer or appropriate third party which are in addition to our main network, connection and metering services and are levied as a separate charge. Fee Based Services have a 'fixed fee' 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. Large Customer Connections, and emergency recoverable works etc.).[1]
- *ACS – Street Lighting Services* – relate to the installation, operation and maintenance of street lighting assets owned by Ergon Energy. Ergon Energy recovers our costs in providing ACS – Street Lighting Services through a daily street lighting charge which we bill to retailers.

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. This section

[1] The prices set out in this Pricing Proposal are examples of potential prices for Quoted Services.

aims to assist customers and other interested parties in understanding how network tariffs are developed and applied.

- Part 2 details how this Pricing Proposal satisfies the requirements of the NER and the AER's Final Distribution Determination.

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 as defined in the NER.

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 to 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, tariff codes, loss factors and detailed information about operational issues relating to Standard and Alternative Control Services.[2]

The "Network Tariff Guide for Standard Control Services" and the "Price List for Alternative Control Services" will also set out the tariffs and prices for 2014–15 and any other changes that are required as a result of this Pricing Proposal, once approved.

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

Figure 1.1: Supporting network pricing documentation

Information Guide for Standard Control Services Pricing

- Sets out the basis upon which Ergon Energy's Annual Revenue Requirement for Standard Control Services is recovered from various customer groups through network tariffs
- Provides a description of the network tariffs
- Published annually

Network Tariff Guide for Standard Control Services

- 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
- Provides details on the assignment of customers to tariff classes and network tariffs
- 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, and details the basis of Quoted Services pricing, including Large Customer Connections from 2010-11
- Published annually

Price List for Alternative Control Services

- Sets out Ergon Energy's Alternative Control Services and the prices that apply for ACS - Street Lighting Services and Fee Based Services
- Published annually, and updated as required

Capital Contributions Policy

- Details the circumstances in which a capital contribution may be required and how Ergon Energy calculates the capital contribution to be paid when a customer applies for a connection to the distribution network
- This policy was approved by the Queensland Competition Authority (QCA) in 2005 and continues to be in force under the AER during the current regulatory control period

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PART 1 – APPROACH TO PRICE SETTING

2 Matters impacting Ergon Energy's revenue and network prices for 2010–15

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 Final Distribution Determination for the 2010–11 to 2014–15 period

On 6 May 2010, the AER made its Distribution Determination for regulated distribution services provided by Ergon Energy. The Distribution Determination effectively sets the revenue and pricing control regime that Ergon Energy must comply with over the current regulatory control period (i.e. 2010–15) for these services.

2.1.2 Review of the Final Distribution Determination

On 19 May 2011, the Australian Competition Tribunal (Tribunal) varied aspects of Ergon Energy's revenues allowed for in the AER's Final Distribution Determination made on 6 May 2010. The Tribunal also varied the AER's Final Distribution Determination to allow Ergon Energy to charge customers other one-off costs we incur in the delivery of Quoted Services.

Further information on the revised revenues and formulas used by Ergon Energy in the calculation of prices for Standard Control Services and Alternative Control Services as a result of the Tribunal outcomes is set out in our 2011–12 Pricing Proposal, which was approved by the AER on 9 June 2011.[3]

2.2 Queensland Government

2.2.1 Queensland Electricity Network Capital Program Review

On 11 February 2012, Ergon Energy received a direction notice from the Queensland Government under section 115 of the *Government Owned Corporations Act 1993* to not recover a portion of our AER-approved revenue allowances for Standard Control Services for the remainder of the regulatory control period (i.e. 2012–13 to 2014–15). This revenue adjustment relates to capital expenditure (capex) savings identified through the 2011 Electricity Network Capital Program (ENCAP) Review[4] findings and recommendations endorsed by the Queensland Government. Ergon Energy was also directed to not recover the foregone revenue associated with the ENCAP Review from customers in future years.

To give effect to this direction, Ergon Energy made an adjustment to the smoothed revenues to be collected from Distribution Use of System (DUOS) charges after performing the Maximum Allowable Revenue (MAR) and unders and overs calculations in 2012–13 and 2013–14. Effectively, this means Ergon Energy did not recover our full revenue allowances in these years. The AER approved this approach in our 2012–13 and 2013–14 Pricing Proposals.[5]

[3] Available at http://www.aer.gov.au/node/6446.
[4] Available at http://www.business.qld.gov.au/industry/energy/electricity-industry/electricity-queensland/review-electricity-distributors.
[5] Available at http://www.aer.gov.au.

2.2.2 Queensland Electricity Sector Reform

In 2012, the Queensland Government carried out a number of reviews of Queensland's electricity sector to address rising electricity costs. In particular, the Queensland Government established an Interdepartmental Committee (IDC) on Electricity Sector Reform in May 2012 to review all aspects of the sector that impact on electricity costs. The objectives of the IDC were to ensure:

1. *"Electricity in Queensland is delivered in a cost-effective manner for consumers;*
2. *Queensland has a viable, sustainable and competitive electricity industry; and*
3. *Electricity is delivered in a financially sustainable manner from the Queensland Government's perspective."* [6]

The IDC published its final recommendations in May 2013. The Queensland Government accepted, or accepted in principle, most of these recommendations.[7]

At the time of submitting this Pricing Proposal, the impacts of the Queensland Electricity Sector Reform are not known. Therefore, it may be necessary for Ergon Energy to amend the prices included in this Pricing Proposal. Further information on adjustments to tariffs within a regulatory year is detailed in Section 8.2.

2.3 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 and 'wide screen' televisions), led to a dramatic increase in demand for electricity during peak usage 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 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 incorporated into our 2014–15 Pricing Proposal. To help develop the tariff changes outlined here we have consulted with a wide range of our customers and our stakeholders over the past year. The resulting short, medium and longer term tariff development intentions have been available and progressively updated on our website since June 2013,[8] and have been subject to two formal 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 making the decisions around any future use of new energy-related technologies, such as solar-fed batteries, electric vehicles and home automation, or any other innovations.

In broad terms, Ergon Energy proposes to make the following changes to network tariffs in 2014–15:

- introduce kVA as the basis for the demand tariffs used by our very large energy users
- commence the process of 'rebalancing' tariffs towards more fixed/less usage-dependent charges for our large and small users

[6] Department of Energy and Water Supply (2012), *IDC on Electricity Sector Reform – Terms of Reference*, http://www.dews.qld.gov.au/policies/electricity-sector-reform, Accessed on 15 April 2013.
[7] Available at http://www.dews.qld.gov.au/__data/assets/pdf_file/0007/78568/queensland-government-response-to-idc-report.pdf.
[8] www.ergon.com.au/futurenetworktariffs

- introduce new and optional broad-based tariff structures for our smaller customers.

Further information on the 2014–15 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 are likely to evolve on a continuous basis, in contrast to the structural stability displayed over the past 15 years.

3 Establishing 2014–15 tariffs for Standard Control Services

3.1 Overview

Ergon Energy's Standard Control Services are regulated under a revenue cap form of price control. Generally, the revenue cap for any given year reflects Ergon Energy's MAR plus any under/over adjustment required to clear the DUOS unders and overs account for the most recently completed regulatory year (i.e. for 2014–15 prices, the under/over recoveries relating to 2012–13). The resulting Annual Revenue Requirement (ARR) 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), as identified in Section 3.4, are then allocated to customers.

3.2 Revenue recovery in 2014–15

In 2014–15, the total network (transmission and distribution) revenue that Ergon Energy will need to recover from network users is approximately $2,158 million. This is an increase of 11.81 per cent above what we expected to recover from network users in 2013–14.

The amount to be recovered includes Ergon Energy's ARR of approximately $1,838 million. This reflects adjustments made to Ergon Energy's 2014–15 Allowed Revenue (AR) for:

- the difference between forecast and actual inflation
- the Service Target Performance Incentive Scheme (STPIS)
- the difference between forecast and actual capital contributions
- transitional factors, such as unders and overs adjustments for shared assets
- pass throughs for the Solar Bonus Scheme
- unders and overs associated with the DUOS unders and overs account.

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

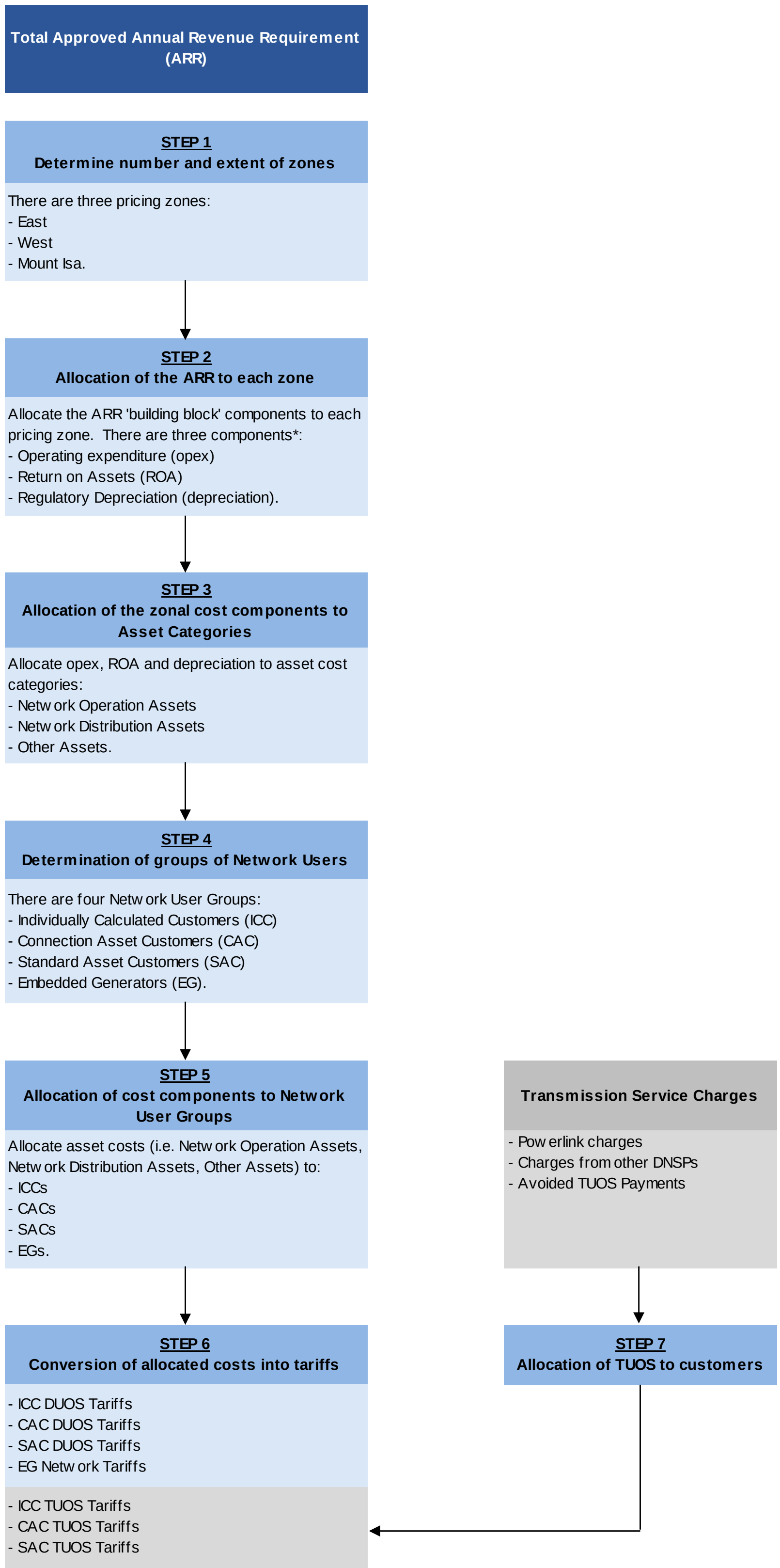
Ergon Energy also recovers revenues on behalf of Powerlink and other designated pricing proposal charges (approximately $320 million) as outlined in Section 3.4.

3.3 Development of network tariffs for Standard Control Services

The process for allocating and converting the ARR to network tariffs for the various customer groups is set out in Figure 3.1 below. Essentially, the ARR 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 is then allocated to customers.

The following sections provide high level information on the pricing zones and the network user groups, as well as the Large 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 allowed revenue (prior to annual revenue adjustments) is determined by the AER using a building block approach. The building block components comprise allowances for ROA, regulatory depreciation (depreciation), opex and a tax allowance. For pricing purposes, revenue associated with the tax allowance 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)[9]
- EGs.[10]

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 per annum (p.a.), or ▪ with energy consumption lower than 40 GWh p.a. where: ○ a customer has a dedicated supply system which is quite different and separate from the remainder of the supply network ○ there are only two or three customers in a supply system making average prices inappropriate ○ a customer is connected at or close to a Transmission Connection Point, or ○ 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: ○ a customer has a dedicated supply system which is quite different and separate from the remainder of the supply network, or ○ 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 a similar service connection and usage profile as other SACs without such facilities. Customers taking supply at LV with a generator installed with a capacity less than or equal to 1MW, will generally be classified as a SAC unless the connection assets are considered to be quite different from that supplying other SACs. 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

[9] Unmetered loads such as street lights are treated as a SAC.
[10] EGs may also take load from the system. The load side will be classified as either an ICC, CAC, or SAC, and a separate network tariff will apply.

Network user group	Description
	▪ 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 ▪ 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 customers with micro generation facilities that have been classified as a SAC. 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:[11]

- **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 "Network Tariff Guide for Standard Control Services".

3.3.3 Large Customer Connection arrangements

Network tariffs for large customers are also differentiated by whether the customer has connected under legacy arrangements where connection assets are included in the network tariff or the new Large Customer Connection arrangements where new or augmented connection assets are paid for or contributed by the customer.

ICCs, CACs and EGs connected under the Alternative Control Services Large Customer Connection arrangements are only able to access post-30 June 2010 network tariffs. These network tariffs differ from those that apply to all other ICCs, CACs and EGs in that they no longer recover the cost of new or augmented dedicated connection assets.[12] Dedicated connection assets for ICCs, CACs and EGs will be levied as an up-front payment, or will be constructed by customers and gifted to Ergon Energy.

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:

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

- 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
- charges or payments specified in clause 11.39 of the NER which include:
  - charges levied on Ergon Energy for use of the 220kV network which supplies the Cloncurry network
  - entry and exit services charged by Powerlink at four connection points – Queensland Nickel,[13] 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 6.13.

3.5 Tariff schedules

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

[13] Following the purchase of the unregulated asset by Queensland Nickel, Queensland Nickel is now taking supply directly from Powerlink. Queensland Nickel is therefore no longer a customer of Ergon Energy.

4 Establishing 2014–15 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 previous years of this regulatory control period. For Fee Based and Quoted Services, a formula based approach is used to determine the efficient costs (and price) of providing the service. This is discussed further in Section 4.2.

For Street Lighting Services, the approach used to determine the efficient costs (and price) will depend on the type of service carried out. Further information on the tariff setting process for the different types of services provided in connection with street lights is detailed in Section 4.4.

4.2 Tariff setting process for Fee Based and Quoted Services

4.2.1 Fee Based Services

In accordance with section 18.4 of the AER's Final Distribution Determination, Ergon Energy will apply the following formula when calculating the tariffs to be levied for our Fee Based Services.

$$\boldsymbol{P_i = L_i + M_i + CA_i + GST_i}$$

Where:

L_i = the cost of labour involved in the delivery of the service, calculated as the product of an hourly rate (inclusive of on-costs and shared costs (overheads)) and the time spent by the personnel involved. The amount of time includes both travel time and the time spent delivering the service.

M_i = the cost of non-capitalised materials expensed in the delivery of the service (inclusive of overheads).

CA_i = reflects the use of non-system physical assets owned by Ergon Energy involved in the delivery of the service. This charge reflects the ROA and depreciation of those assets employed in the delivery of the service (e.g. trucks and IT systems).

GST_i = the Goods and Services Tax component of the service charge.

Ergon Energy may recalculate our labour and material escalators and overheads each regulatory year. Quantitative and qualitative information is provided in the Pricing Proposal where changes have been proposed to the previously approved escalators and overheads. This information is set out in Section 7.3 of this Pricing Proposal.

The calculation of Ergon Energy's Fee Based prices is set out in Appendix 5.

4.2.2 Quoted Services

In accordance with the Tribunal's Determination made on 19 May 2011, Ergon Energy will apply the following formula when calculating the tariffs to be levied for our Quoted Services.

$$P_i = L_i + M_i + OC_i + CA_i + GST_i$$

Where:

L_i = the cost of labour involved in the delivery of the service, calculated as the product of an hourly rate (inclusive of on-costs and shared costs (overheads)) and the time spent by the personnel involved. The amount of time includes both travel time and the time spent delivering the service.

M_i = the cost of non-capitalised materials expensed in the delivery of the service (inclusive of overheads). For new large customer connection services, this could include large scale capital items which are charged directly to customers.

OC_i = other one-off costs (inclusive of overheads) relating to the delivery of the service, including:

(a) the hire or supply of assets and equipment

(b) the supply of services such as contractors and external labour

(c) the cost of permits.

Other Costs are to be charged to customers at their cost to Ergon Energy plus overheads.

CA_i = reflects the use of non-system physical assets owned by Ergon Energy involved in the delivery of the service. This charge reflects the ROA and depreciation of those assets employed in the delivery of the service (e.g. trucks and IT systems).

GST_i = the Goods and Services Tax component of the service charge.

Ergon Energy may recalculate our labour and material escalators and overheads each regulatory year. Quantitative and qualitative information is provided in the Pricing Proposal where changes have been proposed to the previously approved escalators and overheads. This information is set out in Section 7.3 of this Pricing Proposal.

The calculation of Ergon Energy's Quoted Services prices is set out in Appendix 5.

4.3 Queensland Government caps on Fee Based and Quoted Services

The Queensland Government has set maximum price caps to apply to a subset of Ergon Energy's Fee Based and Quoted 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.

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 2014–15 as a result of Schedule 8 maximum price caps, and hence the prices customers will be charged.

4.4 Tariff setting process for Street Lighting Services

4.4.1 Types of Street Lighting Services

Ergon Energy provides three types of Alternative Control Services in connection with street lights:

- Street Lighting Service 1 – provision of new street lighting assets
- Street Lighting Service 2 – operation, repair, replacement and maintenance of street lighting assets
- Street Lighting Service 3 – alteration and relocation of existing street lighting assets.

Street Lighting Service 3 is a Quoted Service. This means the costs to Ergon Energy in undertaking this work is not recovered through the daily street lighting charge, but is instead recovered through separate upfront charges levied on those who utilise the service. Tariffs for Street Lighting Service 3 are calculated on a price on application basis in accordance with the formula for Quoted Services set out in Section 4.2.2 of this Pricing Proposal.

Street Lighting Services 1 and 2 are the only elements of service which are factored into Ergon Energy's ACS – Street Lighting Services. They have been developed on a limited building block approach which includes the ROA, depreciation, opex and tax allowance for all street lights installed prior to 30 June 2010, and new street lights forecast to be installed by or gifted to Ergon Energy after 30 June 2010.

Based on the approved ARR for ACS – Street Lighting Services, Ergon Energy calculated a daily charge ($/light/day) for Major and Minor street lights within each of the East, West and Mount Isa zones based on:

- the number of Major and Minor street lights within each zone
- the asset values of Major and Minor street lights.

Street lights owned and maintained by Ergon Energy are distinguished between Major and Minor on the following basis:

- **Major street lights** – Ergon Energy standard major street lights are 100, 150, 250 and 400 watt High Pressure Sodium vapour lights and include any other non-standard or obsolete street lights that would be replaced with any of the above Ergon Energy standard major street lights in accordance with Ergon Energy policy.
- **Minor street lights** – Ergon Energy standard minor street lights are 50, 80 and 125 watt Mercury Vapour, 70 watt High Pressure Sodium vapour lights, and compact fluorescent lights of similar luminescence and include any other non-standard or obsolete street lights that would be replaced with any of the above Ergon Energy standard minor street lights in accordance with Ergon Energy policy.

4.4.2 Calculating ACS – Street Lighting Services Tariffs

Ergon Energy uses the following methodology to calculate ACS – Street Lighting Services tariffs:

Step 1: Determination of zones

Three pricing zones have been delineated in the Ergon Energy area of supply. The zones are the East Zone, the West Zone and the Mount Isa Zone. Further information on the zones is provided in Section 3.3.2 above.

Step 2: Allocation of the ARR to zones and street light type

The second step in the ACS – Street Lighting Services tariff development process is to allocate the ARR to each of the three zones. This is based on the street lighting asset values within each zone which is determined by the proportion of the value of Major and Minor street lights within each zone.

Step 3: Conversion of the allocated ARR into street light tariffs

The pro-rated Street Lighting ARR by Major and Minor street lights for each zone is then converted to a dollars per day tariff for each street light type in each zone. This approach ensures that costs are allocated in a cost-reflective manner to each of the street light types.

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

The amount payable will be the incremental cost difference between a standard and non-standard street 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 ACS – Street Lighting Services over the life of a standard street light asset. This revenue is calculated using the relevant daily street lighting charge, and
- the estimated cost of providing the non-standard street lighting asset. These costs are calculated in accordance with the formula for Quoted Services set out in Section 4.2.2.

4.5 Tariff schedules

Appendix 4 sets out the 2014–15 tariffs for our Alternative Control Services. Specifically, it sets out the prices for Fee Based Services and ACS – Street Lighting Services and examples of potential prices for Quoted Services for 2014–15.

In relation to each Quoted Service, it is important to note that the prices set out 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.

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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 (clause 6.18.2(b)(7)). In addition, Ergon Energy must comply with matters arising from the Tribunal's review of the AER's Final Distribution Determination.

Ergon Energy's compliance with the requirements is set out in the following sections. For ease of reference, a summary of the obligations is also provided in Tables 5.1, 5.2 and 5.3.

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.
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 our SAC <100 MWh p.a., SAC >100 MWh p.a. and ICC groupings, which are set out in Table 8.1. Tariff schedules for Alternative Control Services are provided in Appendix 4.
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. Ergon Energy has not altered the charging parameters which will apply in 2014–15. However, for SACs <100 MWh p.a., the volume charges which apply to energy metered at a customer's installation will now be based on an inclining block or Time-of-Use (TOU) charging structure (depending on the applicable network tariff), instead of a flat rate. For SACs >100 MWh p.a., the minimum chargeable actual demand charge that applied in 2013–14 has been restructured into the fixed charge. An actual demand charge still applies. For Alternative Control Services, the charging parameters are fixed by the control mechanism imposed by the AER and outlined in Section 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.
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.	We are not proposing to make any variations or adjustments to our SAC tariffs (including the Inclining Block Tariff (IBT) or TOU tariffs) during the course of 2014–15 as a result of the Network Tariff Strategy changes. Variations and adjustments which could apply to tariffs during 2014–15 are set out in Section 8.2.

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 6.13. In 2014–15, Ergon Energy is making changes to the way TUOS is recovered from our ICCs and SACs >100MWh p.a. to align to changes that are occurring in the DUOS space. There will be no change for SACs <100 MWh p.a. A description of how TUOS will be passed through to customers under the new tariffs is included in Section 8.3.
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.	Ergon Energy is not yet operating under the jurisdictional scheme cost recovery provisions in Chapter 6 of the NER. Ergon Energy's ARR for Standard Control Services includes an allowance to recover payments made by Ergon Energy under the Solar Bonus Scheme, in accordance with arrangements in the AER's Final Distribution Determination.
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.	Ergon Energy is not yet operating under the jurisdictional scheme cost recovery provisions in Chapter 6 of the NER.
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 Final Distribution 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.	As noted in Section 2.3, Ergon Energy is proposing a number of changes to our network tariff structures from 1 July 2014 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 Section 8.3. 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.
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.

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. For SACs <100 MWh p.a., Ergon Energy has avoided unnecessary transaction costs by replacing the existing Volume Small and Volume Large network tariffs with Residential and Business segmentation. This means Ergon Energy will not need to reallocate customers to different tariff classes. Further, customers will only need to expressly request a tariff change if they wish to take up a different network tariff under the new structure (e.g. TOU Residential). No structural changes are proposed for ICC, CAC or SAC >100 MWh p.a. network tariffs.
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. It should be noted that the charging parameters within our network tariffs do not alter as the customer's usage or load profile varies. However, the introduction of the IBT for SACs <100 MWh p.a. means that the actual network charges applied will vary according to the customer's level of consumption. For those SACs <100 MWh p.a. who opt into the TOU tariffs, the network charges will vary according to when their consumption occurs.
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 6.8 and 7.6. For Standard Control Services, Ergon Energy has revised our methodology since 2013–14, with a view to developing a more robust estimation approach.

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
6.18.5(b)(1)	Demonstrate that tariffs and charging parameters have regard for Long Run Marginal Cost (LMRC).	Ergon Energy considered LRMC and other economic principles when considering options to restructure our network tariffs. LRMC is dealt with in Sections 6.9 and 7.7.
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.	In 2014–15, we have altered the structure or format of some of our network tariffs from those applying in the previous regulatory year. However, we consider that the changes for ICCs and SACs >100 MWh p.a. have been relatively easy to develop and are not expected to impose implementation costs on Ergon Energy or retailers. The IBT and optional TOU structures we are proposing for our SACs <100 MWh p.a. achieve an appropriate balance between minimising administrative complexity and sending meaningful signals to customers. Further information on tariffs and transaction costs is contained in Sections 6.10 and 7.7.
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 6.11 and 7.7. Section 6.11 has been revised to reflect the price signals associated with IBT and TOU tariffs.
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 dealt with in Section 6.7.
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.	Side constraints are dealt with in Section 6.7.
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.	Side constraints are dealt with in Section 6.7.
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.	Side constraints are dealt with in Section 6.7.
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 6.13.
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 6.13.

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
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 6.13.
6.18.7 A (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.	Ergon Energy is not yet operating under the jurisdictional scheme cost recovery provisions in Chapter 6 of the NER.
6.18.8(a)(2)	Demonstrate that all forecasts associated with the proposal are reasonable.	The methodology used to forecast customer numbers, energy consumption, demand and TUOS payments is consistent with the overarching method used by Ergon Energy in 2013–14. In 2014–15, additional granularity of our forecasts has been undertaken to support the new SAC <100 MWh p.a. IBT and TOU tariff structures. 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.
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.	Refer to Sections 6.12 and 7.8. Ergon Energy's regulatory control period ends on 30 June 2015.
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 Final Distribution Determination

Obligation	Demonstration of compliance in this Pricing Proposal
Set out a method of reviewing and assessing the basis on which a customer is charged in accordance with Appendix B of the Final Distribution Determination.	Tariff assignment and the assessment and review of the basis of charge are dealt with in Sections 6.2 and 7.2.
Set out any unders/overs adjustment needed to move the balance of DUOS unders and overs account to zero (or agreed tolerance level) in accordance with Appendix D of the Final Distribution Determination.	Unders/overs adjustments needed to move the balance of DUOS unders and overs account to zero (or agreed tolerance level) is set out in Section 6.5.2.
Set out a record of the amount of revenues recovered from TUOS charges and associated payments in accordance with Appendix E of the Final Distribution Determination.	Revenues recovered from TUOS charges and associated payments are set out in Section 6.13.

Obligation	Demonstration of compliance in this Pricing Proposal
Set out proposed prices for Street Lighting Services in accordance with section 17.3.3 of the Final Distribution Determination.	Prices for ACS – Street Lighting Services are set out in Appendix 4.
Set out revenue collected from Street Lighting Services in the preceding regulatory year in accordance with section 17.3.3 of the Final Distribution Determination.	Revenue recovered from ACS – Street Lighting Services in 2012–13 is set out in Appendix 6.
Set out prices for Fee Based Services and examples of potential Quoted Services.	Prices for Fee Based and Quoted Services are set out in Appendix 4.
Set out quantitative information that demonstrates the calculation of prices for Quoted and Fee Based Services.	A quantitative demonstration of the calculation of Fee Based and Quoted Services is set out in Appendix 5.
Set out the nature and extent of variation to individual formula components in accordance with section 18.3.5 of the Final Distribution Determination.	Variations to individual formula components for Fee Based and Quoted Services are set out in Section 7.3.1.
Set out the nature and extent of any changes to the methodology used to calculate individual formula components in accordance with section 18.3.5 of the Final Distribution Determination.	Changes to the methodology used to calculate individual formula components for Fee Based and Quoted Services are set out in Section 7.3.2.
Set out the AER's requirement to provide the volume of Fee Based and Quoted Services provided and the revenues recovered from the provision of Fee Based and Quoted Services as required by section 18.3.5 of the Final Distribution Determination.	Fee Based and Quoted Services provided and the revenues recovered from the provision of Fee Based and Quoted Services in 2012–13 are set out in Appendix 6.

Table 5.3: Australian Competition Tribunal compliance outcomes

Matter	Obligation	Demonstration of compliance in this Pricing Proposal
Tribunal Determination (Other Costs)	Set out the AER's requirement to report on any departures from procurement processes and procedures in delivering Quoted Services that include Other Costs as required by the Tribunal Determination (Other Costs).	Departures from procurement processes and procedures are set out in Section 7.9.

6 Standard Control Services

6.1 Tariff classes

As noted in Section 3.3 of this Pricing Proposal, 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
- whether the large customer is subject to the previous arrangements where connection assets form part of the network tariff or the Large Customer Connection process where new or augmented connection assets are paid for or contributed by the customer.[14]

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)[15] and clause 6.18.3(a)[16] of the NER. There are 27 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 (Pre 30 June 2010) – East	ICC	EICCKA1 onwards
Individually Calculated Customer (Pre 30 June 2010) – West	ICC	WICCKA1 onwards
Individually Calculated Customer (Pre 30 June 2010) – Mount Isa	ICC	MICCKA1 onwards
Individually Calculated Customer (Post 30 June 2010) – East	ICC	EICCKB1 onwards
Individually Calculated Customer (Post 30 June 2010) – West	ICC	WICCKB1 onwards
Individually Calculated Customer (Post 30 June 2010) – Mount Isa	ICC	MICCKB1 onwards
Connection Asset Customers (Pre 30 June 2010) – East	CAC	ECACA1 onwards
Connection Asset Customers (Pre 30 June 2010) – West	CAC	WCACA1 onwards
Connection Asset Customers (Pre 30 June 2010) – Mount Isa	CAC	MCACA1 onwards
Connection Asset Customers (Post 30 June 2010) – East	CAC	ECACB1 onwards
Connection Asset Customers (Post 30 June 2010) – West	CAC	WCACB1 onwards
Connection Asset Customers (Post 30 June 2010) – Mount Isa	CAC	MCACB1 onwards

[14] It should be noted that in some instances pre 30 June 2010 tariffs will apply to customers that connect after 30 June 2010. This is because the nature and/or timing of the connection application require that these customers be recognised under the previous arrangements. In these circumstances, customers will be notified that the tariffs for the pre 30 June 2010 tariff class will apply.
[15] This clause requires a Pricing Proposal to set out the tariff classes that are to apply for the relevant regulatory year.
[16] 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
Embedded Generation (Pre 30 June 2010) – East	EG	EEGA1 onwards
Embedded Generation (Pre 30 June 2010) – West	EG	WEGA01 onwards
Embedded Generation (Pre 30 June 2010) – Mount Isa	EG	MEGA01 onwards
Embedded Generation (Post 30 June 2010) – East	EG	EEGB1 onwards
Embedded Generation (Post 30 June 2010) – West	EG	WEGB01 onwards
Embedded Generation (Post 30 June 2010) – Mount Isa	EG	MEGB01 onwards
Standard Asset Customer – Large (>100 MWh p.a.) – East	Demand High Voltage	EDHTT1, EDHTT2, EDHTT3
	Demand Large	EDLTT1, EDLTT2, EDLTT3
	Demand Medium	EDMTT1, EDMTT2, EDMTT3
	Demand Small	EDSTT1, EDSTT2, EDSTT3
Standard Asset Customer – Large (>100 MWh p.a.) – West	Demand High Voltage	WDHTT1, WDHTT2, WDHTT3
	Demand Large	WDLTT1, WDLTT2, WDLTT3
	Demand Medium	WDMTT1, WDMTT2, WDMTT3
	Demand Small	WDSTT1, WDSTT2, WDSTT3
Standard Asset Customer – Large (>100 MWh p.a.) – Mount Isa	Demand High Voltage	MIDHT
	Demand Large	MIDLT
	Demand Medium	MIDMT
	Demand Small	MIDST
Standard Asset Customer – Small (<100 MWh p.a.) – East	Business – IBT	EBIBT1, EBIBT2, EBIBT3
	Business – TOU	EBTOUT1, EBTOUT2, EBTOUT3
	Residential – IBT	ERIBT1, ERIBT2, ERIBT3
	Residential – TOU	ERTOUT1, ERTOUT2, ERTOUT3
	Volume Controlled	EVCT1, EVCT2, EVCT3
	Volume Night Controlled	EVNT1, EVNT2, EVNT3
Standard Asset Customer – Small (<100 MWh p.a.) – West	Business – IBT	WBIBT1, WBIBT2, WBIBT3
	Business – TOU	WBTOUT1, WBTOUT2, WBTOUT3
	Residential – IBT	WRIBT1, WRIBT2, WRIBT3
	Residential – TOU	WRTOUT1, WRTOUT2, WRTOUT3
	Volume Controlled	WVCT1, WVCT2, WVCT3
	Volume Night Controlled	WVNT1, WVNT2, WVNT3
Standard Asset Customer – Small (<100 MWh p.a.) – Mount Isa	Business – IBT	MIBIB
	Business – TOU	MIBTOU
	Residential – IBT	MIRIB
	Residential – TOU	MIRTOU
	Volume Controlled	MIVC
	Volume Night Controlled	MIVN

Tariff class	Tariff	Network Tariff Codes
Standard Asset Customer – Unmetered – East	Volume Unmetered	EVUT1, EVUT2, EVUT3 EVUT1MI, EVUT2MI, EVUT3MI EVUT1MA, EVUT2MA, EVUT3MA
Standard Asset Customer – Unmetered – West	Volume Unmetered	WVUT1, WVUT2, WVUT3 WVUT1MI, WVUT2MI, WVUT3MI WVUT1MA, WVUT2MA, WVUT3MA
Standard Asset Customer – Unmetered – Mount Isa	Volume Unmetered	MIVU, MIVUMI, MIVUMA

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 below.

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[17] 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. For example, Ergon Energy has subdivided the 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 will help promote economic efficiency while avoiding costly tariff proliferation.[18]

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.

6.2 Assignment and reassignment of customers to tariff classes

Appendix B of the AER's Final Distribution Determination sets out its 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:

[17] Refer to Appendix 1 of Ergon Energy's "Information Guide for Standard Control Services Pricing".
[18] As a result of the Network Tariff Strategy, Ergon Energy has changed the classification within the SAC <100 MWh p.a. tariff classes. The existing consumption-based segmentation (i.e. Volume Small and Volume Large) has been replaced with segmentation based on the type of customer (i.e. Residential or Business).

(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 Appendix B of the AER's Final Distribution 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) 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).

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 would only occur 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
SACs	▪ 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.
CACs	▪ 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.[19]
ICCs	▪ 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

[19] 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 threshold.

- within a network tariff, it is appropriate to change the charging parameter/s because of changes according 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 "Network Tariff Guide for Standard Control Services".

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, actual 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 IBT, the actual network charges applied to them will vary according to their level of usage. Similarly, for SACs <100 MWh p.a. on TOU tariffs, the network charges will vary according to when their usage occurs.

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 and their retailer prior to the assignment or reassignment occurring. The written notice includes:

- advice that the customer 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 the customer is entitled to seek resolution via the dispute resolution process under Part 10 of the Law, if the objection is not resolved by Ergon Energy to the satisfaction of the customer.

In addition, the "Network Tariff Guide for Standard Control Services" sets out the circumstances when a tariff class assignment and reassignment may occur, and provides details on how the customer or retailer can request further information on a tariff class assignment, and the procedures to follow if the customer objects to a proposed tariff class assignment or reassignment. This information is also available in the "Retailer Handbook" issued and available to retailers operating in Ergon Energy's distribution area.

6.2.4 Objections to a tariff class assignment or reassignment

If either the customer or 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 customer, the customer is entitled to refer the matter to the AER for resolution via the dispute resolution process available under Part 10 of the Law.

At the time of preparing this Pricing Proposal, Ergon Energy had not received any objections to a tariff class assignment or reassignment relating to Standard Control Services that occurred during the 2013–14 year.

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 and the impact of their usage on future network capacity and costs.

The following charging parameters have been adopted in 2014–15.

6.3.1 Fixed charges

The fixed charge has been applied to serve two broad purposes. For some customers within a tariff class, it seeks to reflect the incremental costs that arise from the connection and management of the network user. The fixed charge is also used to help recover a share of residual or sunk elements of Ergon Energy's costs. For example, for SACs <100 MWh p.a., the fixed charge also recovers a portion of the shared network costs.

6.3.2 Capacity and actual demand charges

Shared network costs for ICCs, CACs and SACs >100 MWh p.a. are recovered through the capacity charge and/or actual demand charge components. These charges provide economic signals to the customers on the existing and future use of the shared network on the basis that customers who place greater pressure on the system incur higher charges.

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.

The demand used for the calculation of the actual demand charge is the annual average demand (i.e. the average of the monthly maximum demands 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 average demand may be substituted.

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

For SACs >100 MWh p.a., an actual demand charge applies. However, the minimum chargeable actual demand charge that applied instead of a capacity charge up until 2013–14 has been restructured into the fixed charge (refer to Section 8.3).

SACs <100 MWh p.a. do not have either a capacity charge or an actual demand charge.

6.3.3 Volume charges

The volume charge in part recovers costs that have been allocated on a postage stamped basis. For SACs <100 MWh p.a., the volume charge also recovers a portion of the shared network costs not included in the fixed charge.

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 2014–15 tariffs for Standard Control Services are set out in Appendix 1 and Appendix 2.

6.5 Revenue is consistent with MAR formula

Section 4.5.1 of the AER's Final Distribution 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 MAR formula, plus any unders or overs adjustment needed to move the balance of the DUOS unders and overs account to zero.

This section sets out the manner in which prices have been developed based on revenue that has regard for all necessary adjustments.

The resulting revenue cap calculation for 2014–15 is demonstrated in Appendix 2.

6.5.1 Calculation of the MAR

In accordance with section 4.5.1 of the Final Distribution Determination, Ergon Energy applies the following formulas when calculating the AR[20] and the MAR for a given regulatory year.

$$\boldsymbol{MAR_t = AR_t \pm S_t \pm C_t \pm transitional_t \pm passthrough_t}$$

Where:

AR_t is the allowed revenue for regulatory year *t*

S_t is the STPIS factor to be applied in regulatory year *t*

C_t is the annual adjustment factor for the difference between actual and forecast capital contributions in year *t*–2 and indexed for two years by the nominal rate of return

$transitional_t$ is a transitional factor for matters such as unders and overs in tax paid during the current regulatory period and unders and overs adjustments related to standard shared assets used for purposes other than Standard Control Services

$passthrough_t$ is the approved pass through amounts with respect to regulatory year t, as determined by the AER.

[20] The AR is an input into the calculation of Ergon Energy's MAR. It reflects adjustments made to the smoothed revenue requirements originally set out in the AER-approved Post Tax Revenue Model (PTRM) for actual inflation.

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

Where:

AR_{t-1} is the allowed revenue for regulatory year *t-1*

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 March in year *t-2* to March in year *t-1*

X_t is the X factor for each year of the next regulatory control period as determined by the PTRM.[21]

6.5.2 Adjustments to the MAR Calculation

DUOS unders and overs account

Under section 4.6 of the Final Distribution Determination, the ARR for any given regulatory year is the MAR, plus any under/over adjustment required to 'clear' any under or over recovery in actual DUOS revenue from the most recently completed regulatory year (subject to tolerance limits).

This annual unders and overs process ensures Ergon Energy recovers no more and no less than the MAR approved by the AER for any given regulatory year.[22] Under these arrangements there is a two year lag between the year in which the under or over recovery occurs and the year in which the adjustment is made to network tariffs to account for any DUOS under or over recovery.

The AER requires that Ergon Energy maintain a DUOS unders and overs account which is to be provided to the AER in this Pricing Proposal.

Table 6.3 below sets out the DUOS unders and overs account, in accordance with Appendix D of the Final Distribution Determination.

[21] Note that the Tribunal varied the outcomes from the Final Distribution Determination including the X factor to be applied in 2014–15.
[22] Subject to other adjustments made as the result of the Tribunal's decision on gamma and the ENCAP Review.

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

	2012–13 Actual	2014–15 Forecast	
Revenue from DUOS charges	$1,332,656	$1,838,309	
Less under/over adjustment approved by regulator for year t-2	$21,043	n/a	
Reversal of benchmark tax liability	$0	$0	
Reversal of ENCAP Review revenue	($57,029)	$0	
Less MAR for the relevant year	$1,402,886	$1,750,770	
Allowed Revenue (AR)	$1,362,301	$1,573,963	
STPIS	($13,528)	$31,479	*
Capital Contribution unders/overs adjustment	$50,899	$63,652	
Transitional adjustments	($1,541)	($2,344)	
Approved pass throughs	$4,755	$84,020	
Under/over recovery for the regulatory year	($34,244)	$87,539	
DUOS unders and overs account			
Nominal Weighted Average Cost of Capital (WACC) – as determined by AER	9.72%		
Opening balance	($91,033)	($141,106)	
Interest on opening balance	($8,848)	n/a	
Under/over recovery for regulatory year	($34,244)	$87,539	
Interest on under/over recovery for regulatory year	($6,981)	n/a	
Closing balance	($141,106)	($53,567)	

* Note this adjustment has been calculated based on the S Factor confirmed by AER correspondence dated 21 February 2014.

Tolerance limits for clearing the DUOS unders and overs account

Section 4.4.2 of the AER's Final Distribution Determination sets out the tolerance limits that are to apply to DUOS under and over recoveries. If the DUOS under or over recovery compared to the MAR for year t is:

- less than 2 per cent, the DUOS under or over recovery will be cleared within one regulatory year
- between 2 per cent and 5 per cent, the DUOS under or over recovery can be spread over two regulatory years
- greater than 5 per cent, Ergon Energy must submit a plan to the AER detailing how we propose to clear the balance of the DUOS unders and overs account.

Ergon Energy has applied the following formula in determining whether the adjustment required to clear Ergon Energy's DUOS unders and overs account in 2014–15 will exceed any of the tolerance limits set out in the AER's Final Distribution Determination.

$$\textit{DUOS under/over recovery threshold}_t = \frac{\textit{DUOS under/over balance} + \textit{DUOS under/over}_t}{\textit{MAR}_t}$$

Where:

DUOS under/over balance is the closing balance from the DUOS unders and overs account in year t-1 and indexed for one year by the nominal rate of return

DUOS under/over$_t$ is the under/over recovery associated with DUOS revenue in year t-2 and indexed for two years by the nominal rate of return

MAR$_t$ is the Maximum Allowable Revenue in year *t* as determined by the formula set out in section 4.5.1 of the Final Distribution Determination.

Ergon Energy has under-recovered our revenue allowance associated with DUOS charges for the 2012–13 regulatory year by $41.23 million (2014–15 dollars). Combined with the DUOS unders and overs opening balance of $99.88 million associated with the 2010–11 and 2011–12 under-recoveries, this represents 8.06 per cent of Ergon Energy's MAR for 2014–15. This means the 5 per cent tolerance limit has been exceeded and Ergon Energy will need to provide a plan to the AER detailing how we propose to clear the balance of the DUOS unders and overs account.

Proposed plan to clear DUOS under-recoveries

To ensure customers do not experience price shocks, Ergon Energy proposes to spread the DUOS under-recoveries beyond the end of the current regulatory control period. In the network tariffs we set for 2014–15, Ergon Energy will clear the remaining balance of the 2010–11 under-recovery and most of the 2011–12 under-recovery. This represents substantial progress in the clearing of the under-recovery balance. However, in saying that, we will not clear any of the 2012–13 under-recovery in 2014–15. Instead, this amount, along with the remaining balance of the 2011–12 under-recovery, will be cleared by making a carry forward adjustment in the PTRM in the next regulatory control period.

This approach is consistent with tolerance limit arrangements that apply to the DUOS unders and overs account set out in section 4.4.2 and Appendix D of the AER's Final Distribution Determination, and with our previous DUOS under recovery plan detailed in our 2013–14 Pricing Proposal.

Appendix 7 provides further details on our proposed plan to clear the DUOS unders and overs account.

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 Side constraints

Clause 6.18.6(b) of the NER requires the expected weighted average revenue to be raised from a Standard Control Services tariff class to not exceed the corresponding expected weighed average revenue from the preceding year by more than a permissible percentage (side constraint).

In section 4.5.2 of the Final Distribution Determination, the AER provides further guidance on side constraints, and requires Ergon Energy to demonstrate that proposed DUOS prices meet the following side constraint formula:

$$\frac{\sum_{j=1}^{m} d_t^j \times q_t^j}{\sum_{j=1}^{m} d_{t-1}^j \times q_t^j} \leq (1+\Delta CPI_t)\times(1-X_t)\times(1+2\%) \pm S_t \pm C_t \pm transitional_t \pm passthrough_t \pm unders\ \&\ overs_t$$

where each tariff class 'j' has up to 'm' components, and where:

d_t^j is the proposed price for component 'j' of the tariff class for year t

d_{t-1}^j is the price charged by the DNSP for component 'j' of the tariff class in year t–1

q_t^j is the forecast quantity of component 'j' of the tariff class in year t

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from March in regulatory year t–2 to March in regulatory year t–1

X_t is the X factor for each year of the regulatory control period. If X>0, then X will be set equal to zero for the purposes of the side constraint formula

S_t is the STPIS factor to be applied in regulatory year t

C_t is the annual adjustment factor for the difference between forecast and actual capital contributions in year t–2

$transitional_t$ is a transitional factor for matters such as unders and overs in tax paid during the current regulatory control period and unders and overs adjustments related to shared assets used for purposes other than Standard Control Services

$passthrough_t$ is an annual adjustment factor that reflects the pass through amounts approved by the AER with respect to regulatory year t

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

Ergon Energy confirms that the weighted average revenue for our tariff classes for 2014–15 is within the percentage allowed by the side constraint formula set out in section 4.5.2 of the Final Distribution Determination (i.e. 23.39 per cent). This is demonstrated in Appendix 2.

Clause 11.16.8 of the NER also sets out a transitional arrangement for Ergon Energy which provides that:

> *For the regulatory control period, nothing in clause 6.18.6 [of the NER] should preclude the implementation of any price paths approved by the QCA (including any necessary adjustment of those price paths in light of the expected revenue for the first regulatory year of the regulatory control period).*

In the 2005–10 regulatory control period, the QCA required Ergon Energy to adopt side constraints on individual contestable customer distribution price increases to a maximum of CPI plus 5 per cent per year.[23] The transitional arrangement set out in clause 11.16.8 of the NER allows Ergon Energy to apply the QCA-approved price paths for some customers which exceed these side constraints. In section 4.5.2 of the AER's Final Distribution Determination, the AER stated that Ergon Energy must continue to comply with the individual side constraints for those customers listed in Table 143 of Ergon Energy's Original Regulatory Proposal.

[23] QCA (2005), *Final Determination on the Regulation of Electricity Distribution*, April 2005, p191.

Ergon Energy has not applied the transitional rule as the customers subject to the QCA-approved price paths have since moved to cost reflective tariffs. This means these customers have the same side constraints applied to them as all other customers in accordance with clause 6.18.6 of the NER.

Ergon Energy confirms that in accordance with clause 6.18.6(e) of the NER, the application of side constraints does not limit the extent a tariff for a customer with remotely read interval metering may vary according to the time or other circumstances of the customer's usage.

6.8 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. These estimations have been revised since 2013–14, with a view to developing a more robust estimation approach. Section 7.6 below sets out the processes for Alternative Control Services.

6.8.1 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 total ARR 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 are 'optimised' by notionally removing some or replacing them with lower capacity assets.

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 were 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. 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 ARR that could be avoided if all other tariff groupings were not served.

6.8.2 Avoidable costs

Previously, Ergon Energy had interpreted the avoidable cost for all tariff classes as the value of the connection assets for the customers within that tariff class. This approach has been revised, in recognition that some proportion of the shared network may also be avoidable if a tariff class were removed.

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

> *"If XX tariff class were 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 ARR that could be avoided, if the tariff grouping under consideration were not served.

6.8.3 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 [NER] 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 relate to their status as a generator.

Table 6.4 below demonstrates that, for each Standard Control Service tariff class containing retail customers, the 2014–15 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 8.

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 (Pre 30 June 2010) – East	$34,142,835	$48,240,871	$790,434,802	Yes
Individually Calculated Customer (Pre 30 June 2010) – West	$12,769,268	$18,041,871	$295,619,090	Yes
Individually Calculated Customer (Pre 30 June 2010) – Mount Isa	$0	$0	$0	Yes
Individually Calculated Customer (Post 30 June 2010) – East	$912,835	$1,289,757	$21,132,894	Yes
Individually Calculated Customer (Post 30 June 2010) – West	$0	$0	$0	Yes

Tariff class	Avoidable costs	Expected revenue	Stand alone costs	Clause 6.18.5(a) met
Individually Calculated Customer (Post 30 June 2010) – Mount Isa	$0	$0	$0	Yes
Connection Asset Customers (Pre 30 June 2010) – East	$64,587,888	$94,942,500	$1,558,199,372	Yes
Connection Asset Customers (Pre 30 June 2010) – West	$9,385,988	$13,797,156	$226,439,377	Yes
Connection Asset Customers (Pre 30 June 2010) – Mount Isa	$0	$0	$0	Yes
Connection Asset Customers (Post 30 June 2010) – East	$3,844,479	$5,651,283	$92,749,036	Yes
Connection Asset Customers (Post 30 June 2010) – West	$684,162	$1,005,700	$16,505,581	Yes
Connection Asset Customers (Post 30 June 2010) – Mount Isa	$0	$0	$0	Yes
Standard Asset Customer – Large (>100 MWh p.a.) – East	$221,303,301	$354,170,263	$422,868,807	Yes
Standard Asset Customer – Large (>100 MWh p.a.) – West	$56,397,121	$90,257,050	$107,764,245	Yes
Standard Asset Customer – Large (>100 MWh p.a.) – Mount Isa	$3,430,433	$5,490,010	$6,554,909	Yes
Standard Asset Customer – Small (<100 MWh p.a.) – East	$571,178,409	$914,514,252	$983,677,303	Yes
Standard Asset Customer – Small (<100 MWh p.a.) – West	$157,440,319	$252,077,832	$271,142,021	Yes
Standard Asset Customer – Small (<100 MWh p.a.) – Mount Isa	$9,243,350	$14,799,536	$15,918,798	Yes
Standard Asset Customer – Unmetered – East	$16,824,551	$16,936,247	$1,075,551,651	Yes
Standard Asset Customer – Unmetered – West	$2,235,802	$2,250,645	$142,929,246	Yes
Standard Asset Customer – Unmetered – Mount Isa	$349,636	$351,957	$22,351,353	Yes

6.9 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.

Ergon Energy interprets LRMC to mean the incremental cost of providing an additional unit of network services when all inputs to the provision of network services can change. This definition incorporates the investment required over time to expand capacity in a network to meet rising demand.

Ergon Energy has taken guidance in relation to the application of LRMC for the purposes of satisfying clause 6.18.5(b)(1) of the NER from the Distribution Pricing Framework Paper (MCE Paper) released by the Ministerial Council on Energy as part of the development of 6.18 of the NER. The MCE Paper, while stopping short of providing a definition for LRMC, noted that it is:

> *...a forward looking concept that relies as much on probability and expectation as on fact. Estimates of marginal cost therefore represent the probability weighted cost of various expectations of demand and supply scenarios.*

Importantly, the MCE Paper did not propose that a DNSP should define LRMC in a numerical sense. Rather, a DNSP should select charging parameters based on long run costs incurred by a DNSP – such as the need for investment in network capacity – which have the potential to alter customer behaviour and which reflect the usage basis of that customer. By structuring tariffs based on charging parameters which signal these long term capacity based costs, a DNSP can ensure that its tariffs (and charging parameters) reflect LRMC.

The MCE Paper did not define a method of determining LRMC – it merely suggested a mechanism by which LRMC could be reflected into prices through the selection of appropriate charging parameters by a utility.

The Standing Council on Energy and Resources (SCER) took over the role of the MCE in late 2011. In September 2013, the SCER submitted a Rule change request to the Australian Energy Market Commission (AEMC) seeking to make extensive changes to Part I of Chapter 6 of the NER. This included the principles for setting distribution tariffs in clause 6.18.5(b) of the NER. In particular, the proposed Rule change would require each tariff and tariff parameters to be "based on" the LRMC of providing the service rather than just "take into account" the LRMC for the service. The proposed Rule change would also require tariffs to be determined having regard to how the LRMC of providing network services could vary by customer location.

The AEMC has recently published a Consultation Paper on the SCER Rule change request, and is currently in the process of preparing its Draft Determination.[24] As such, the proposed changes do not apply to this Pricing Proposal.

In line with previous years, Ergon Energy has determined the proportion of our regulated revenue to be recovered from each tariff class. However, some tariffs and some of the charging parameters within each tariff have changed, in order to better reflect long term costs and encourage efficient usage and investment decisions.

Ergon Energy allocates the ARR 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.

As part of developing our forward Network Tariff Strategy, Ergon Energy engaged Frontier Economics (Frontier) to assist with ensuring our tariff pathway was consistent with economic principles. The Tariff Implementation Report (Attachment 2) explains how Ergon Energy has attempted to use the combination of different charging parameters in order to:

- effectively signal LRMC to customers, and also
- recover the remainder of regulated revenues in ways that seek to avoid distorting network usage

[24] Refer to the *Distribution Network Pricing Arrangements* Rule change available at http://www.aemc.gov.au/Electricity/Rule-changes/Open/distribution-network-pricing-arrangements.html.

decisions away from those based on LRMC signals.

Frontier noted that a framework for economically efficient tariffs will need to consider (among other things):

- the appropriate estimate or proxy for LRMC
- customer decisions and behaviour most likely to require, or bring forward, the need for network augmentation
- the appropriate basis for setting marginal cost based ‘signalling’ tariffs
- the appropriate basis for setting residual ‘cost recovery’ tariffs
- limitations and trade-offs to the development of certain tariff options due to the capabilities of existing metering infrastructure and implementation costs more generally.

The Frontier report notes any estimate of LRMC requires a large number of assumptions to be made, and decision-makers often develop or utilise measures that are designed to act as proxies for LRMC. At a practical level, for the purposes of informing how we take into account LRMC in pricing structures, Ergon Energy has decided to use the Benchmark Cost of Supply (BCS) as a proxy for a broad-based network-wide LRMC. The BCS was originally developed to assess the appropriateness of undertaking non-network alternative initiatives, but it can also be used as an estimate of LRMC across the network as a whole.

More detail of how the BCS is calculated and how LRMC signals and non-LRMC cost recovery were considered for each tariff class (and charging component within the tariff class) can be found in the Tariff Implementation Report.

As highlighted in Section 6.3 of this Pricing Proposal, Ergon Energy uses four broad types of charging parameters to signal LRMC and to recover residual revenue efficiently: fixed charges, capacity and actual demand charges, and volume charges. These charging parameters are applied differently for each tariff class, taking into account the issues identified by Frontier above. A summary of each of these charging parameters is discussed below.

As indicated in Section 2.3, Ergon Energy is planning to modify tariff parameters over time to improve the cost reflectivity and non-distortionary properties of our tariff structures. Improvements under consideration include providing more granularity of cost reflection (e.g. introduction of seasonal TOU parameters) and the extension of demand and capacity charges based on kVA rather than kW to CACs.

6.9.1 Fixed charges

As outlined in Section 6.3.1, Ergon Energy’s fixed charging parameter serves to reflect the costs associated with connection assets and network user management services and, for some tariff classes, is used to recover the residual or sunk network costs.

A fixed charge ($/day) applies to all of Ergon Energy’s customer groups.

6.9.2 Capacity and actual demand charges

As set out in Section 6.3.2, shared network costs for ICCs, CACs and SACs >100 MWh p.a. are recovered through the capacity charge and/or actual demand charge components. These charges provide the economic signals to customers on the use of the shared network.

Demand charges provide an important signal to the customer of the effect of their demand on the need and costs of future system augmentation. However, these charges do not provide adequate signals to customers with a low load factor (i.e. customers which may have infrequent demand usage but impose the same load (and hence, augmentation) requirements on the system as high load factor customers).

A capacity charge is similar to a demand charge, but it provides additional signals to customers with poor load factors. The demand charge uses the actual maximum demand recorded each month, whereas the capacity charge is based on an annual actual or authorised level of demand. Customers with a capacity charge are able to reduce their annual network charges by lowering the variability of their consumption and improving their utilisation of network capacity.

The capacity charge applies to ICC ($/kVA/month) and CAC ($/kW/month) network users only and the actual demand charges ($/kVA or kW/month) apply to ICC, CAC, and SACs >100 MWh p.a. network users.

6.9.3 Volume charges

As set out in Section 6.3.3, volume charges in part recover costs that have been allocated on a postage stamped basis. For SACs <100 MWh p.a., the volume charge also recovers a portion of the shared network costs not included in the fixed charge.

The volume charge applies to the energy (kWh) metered at all ICC, CAC and SAC installations and may be based on a flat rate, an inclining block or TOU charging structure (depending on the applicable network tariff).

6.10 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 developmental and implementation costs and therefore be unlikely to be net beneficial.

Ergon Energy confirms that we have had regard to the transaction costs when selecting our tariffs and charging parameters of tariff classes. Currently, tariffs for higher consumption customers are more sophisticated, are more tailored to the customer and incorporate more charging elements to reflect the costs they impose on the network with more granularity than tariffs for smaller consumption customers. This is because the benefits of more refined tariffs for larger customers outweigh the associated developmental and implementation costs incurred in making these tariffs available to our customers. Ergon Energy has and will continue to undertake stakeholder consultation to inform this trade-off.

For 2014–15, Ergon Energy has altered the structure or format of some of our network tariffs from those applying in the previous regulatory year. For example, ICCs will be charged on the basis of their kVA demand and capacity rather than kW, and the minimum monthly demand charge mechanism for SACs >100 MWh p.a. will be incorporated in the fixed charge and offset by the introduction of a threshold demand mechanism. These changes have been relatively easy to develop and are not expected to impose substantial implementation costs for Ergon Energy or retailers. The introduction of kVA for ICCs will have cost impacts for customers depending on their power factor and individual connection characteristics. Customer impacts are discussed further in Section 8.3.

The changes to the SAC <100 MWh p.a. network tariffs have been more significant in nature. We have replaced the existing consumption-based segmentation (i.e. Volume Small and Volume Large) with segmentation based on the type of customer (i.e. residential and business). We have also introduced new, default network tariffs which comprise a fixed charge and inclining block energy tariff, and new, optional seasonal TOU energy tariffs. Since these network tariffs replace the existing Volume Small and Volume Large network tariffs, Ergon Energy has avoided unnecessary transaction costs by removing the need to reallocate customers to different tariff classes. Further, customers and retailers will only need to expressly request a tariff change if they wish to adopt a different network tariff under the new structure (e.g. TOU Residential).

Ergon Energy also considers that our three-part inclining block structure achieves an appropriate balance between minimising administrative complexity and sending meaningful signals to customers. While a flat volumetric tariff or an IBT with less than three blocks arguably may be less complex to administer (and therefore have lower transaction costs), such a structure would send weak and/or blunt signals to customers about the effect of their usage on the network. Conversely, an IBT with more than three blocks potentially could send clearer signals to customers. However, it would be more complex to administer, and hence would have higher transaction costs. Although minor changes will be required to our network billing systems to implement the new IBT structure, customers and retailers need not incur any additional metering or meter data related costs as a result of its introduction.

In relation to the TOU tariffs, Ergon Energy considers that our Peak, Shoulder and Off-Peak structure achieves an appropriate balance between minimising administrative complexity and sending meaningful price signals to customers. Although a TOU tariff with two time periods and/or no seasonal or weekday/weekend distinction may be less complex to administer (and therefore have lower transaction costs), such a structure does not effectively signal the impact of consumption at times of medium demand (i.e. during the ‘Shoulder’ period), and sends blunt signals to customers about how and when they should alter their pattern of consumption throughout the course of the day, week and year. A TOU tariff with more than three time periods may send even clearer signals to customers. However, it would be more administratively complex and have higher transaction costs.

Ergon Energy will incur some additional costs in implementing and administering the new TOU tariffs (e.g. network billing system changes and upgrading meters to support TOU pricing). However, these costs will be outweighed by the benefits to Ergon Energy (and, ultimately, our customers) as more customers shift to TOU tariffs. This is because Ergon Energy considers that the take up of TOU tariffs will increase over time, and this, in turn, has the potential to reduce our peak demand growth and the associated infrastructure expenditure that would otherwise be required to meet this growth.

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.

6.11 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.

Each charging parameter of Ergon Energy’s tariffs has been developed such that customers are able and likely to respond to price signals.

The fixed charging parameter is designed to recover the fixed cost of a customer’s connection assets. Network users can manage these costs by ensuring that the dedicated connection assets installed match their load and reliability requirement.

The capacity and actual demand charges provide a strong signal to customers on the use of the shared network, and to reduce maximum demands at points of identified constraints. Customers with TOU metering are likely to respond to these signals by reducing or switching their consumption patterns. Customers with relatively flat load profiles who are subject to these tariffs but do not have TOU metering may have incentives to request TOU meters in order to be eligible to receive some reward for the shape of their profile.

The volume charge provides a signal about the effect of increased customer usage on the network, particularly to SACs <100 MWh p.a. who lack TOU metering and may not understand or be familiar with demand-based charges. If customers use more electricity, then they will bear an increasing portion of the ARR and therefore their charges will rise. Given the broad relationship between consumption and peak demand – especially among smaller electricity consumers – volume based charges help signal network costs to such customers in a comprehensible manner. Customers may manage the amount of their charges by reducing their usage. We have seen in the National Electricity Market in recent years that higher (largely volumetric) retail tariffs have been remarkably effective in curbing and even reversing consumption growth among all classes of end-use customers. This means that even smaller customers facing volumetric tariffs are capable and likely to reduce their usage of the network in the face of price signals.

6.12 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.

The NER limits the requirement to provide indicative price trends beyond the current regulatory control period, which ends on 30 June 2015. However, Ergon Energy is committed to improving the affordability of electricity for our customers. We have recently progressed a range of initiatives aimed at limiting future increases in average network charges to CPI or less from 2015–16.

Our Regulatory Proposal will set out indicative prices we propose for Standard Control Services for the 2015–20 regulatory control period. It will be submitted to the AER on 31 October 2014 and will be available on our website at www.ergon.com.au/futureinvestment. The AER will assess our Regulatory Proposal and will release a Distribution Determination in 2015 which ultimately sets the revenue or prices we are allowed to collect or charge for our distribution services in the next regulatory control period.

6.13 Designated pricing proposal charges incurred for TUOS

6.13.1 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 ICCs and CACs, Ergon Energy has a number of regional centres where a meshed distribution network sits below the transmission network. This means customers can be supplied from different connection points depending on switching arrangements. A weighted average methodology is applied for each of these locations so that all customers who are supplied via a regional meshed network have the same TUOS rates.

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.

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 220kV network which supplies the Cloncurry township.

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.

6.13.2 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) 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.*

Appendix E of the AER's Final Distribution 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-recovery or over-recovery occurs and the year in which the adjustment to the expected TUOS revenue to be recovered is made.

Table 6.5 below sets out Ergon Energy's 2012–13 under-recovery based on information lodged in our 2012–13 Annual Performance Regulatory Information Notice (RIN). As highlighted in our 2013–14 Pricing Proposal, Ergon Energy has identified an immaterial misstatement in our TUOS under-recoveries for the 2010–11 and 2011–12 regulatory years. Ergon Energy is proposing an adjustment of $2.05 million to the opening balance of the TUOS unders and overs account to correct these immaterial misstatements. This is subject to approval by the AER as part of this Pricing Proposal.

Table 6.5 satisfies the requirements of Appendix E of the AER's Final Distribution Determination and hence clause 6.18.7 of the NER. Appendix 2 sets out the calculation of the TUOS unders and overs account.

Table 6.5: Calculation of TUOS unders and overs account ($'000)

	2012–13 Actual	2014–15 Forecast
Revenue from TUOS charges	$313,826	$319,836
Less under/over adjustment approved by the regulator for year t-2	$6,922	n/a
Less total transmission related payments	$305,029	$319,732
Transmission charges to be paid to TNSPs	$299,646	$313,579
Avoided TUOS payment to EGs	$2,309	$2,626
Payment to other DNSPs	$3,074	$3,527
Under/over recovery for the regulatory year	$1,875	$104
TUOS unders and overs account		
Nominal WACC – as determined by AER	9.72%	
Opening balance	$0	($104)
Adjustment to opening balance to correct error in 2012–13 account*	($1,018)	
Adjustment to opening balance to correct error in 2013–14 account*	($1,035)	
Interest on opening balance	($308)	n/a
Under/over recovery for regulatory year	$1,875	$104
Interest on under/over recovery for regulatory year	$382	n/a
Closing balance	($104)	($0)

* Note these adjustments are subject to approval by the AER as part of this Pricing Proposal.

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, namely:

- Fee Based Services
- Quoted Services
- ACS – Street Lighting Services.

Fee Based Services are separated into two tariff classes based on the type of feeder to which a customer requesting the service is connected. Specifically, separate tariff classes have been established for Fee Based Services provided to customers connected to:

- urban or short rural feeders
- long rural or isolated feeders.

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 six tariff classes for Alternative Control Services.

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

Tariff class	Product codes
ACS – Fee Based Services (urban/short rural)	DEENBHU, DEENBHS, PROJCTFXU, PROJCTFXS, REENBHU, REENBHS, REDDBHU, REDDBHS, REINSPU, REINSPS, SUBDIVFXU, SUBDIVFXS, SUPABOLU, SUPABOLS, TBSSPU, TBSSPS, TBSMPU, TBSMPS, SFRBHU, SFRBHS, WTVU, WTVS, WTVTU, WTVTS
ACS – Fee Based Services (long rural/isolated)	DEENBHL, DEENBHI, PROJCTFXL, PROJCTFXI, REENBHL, REENBHI, REDDBHL, REDDBHI, REINSPL, REINSPI, SUBDIVFXL, SUBDIVFXI, SUPABOLL, SUPABOLI, TBSSPL, TBSSPI, TBSMPL, TBSMPI, SFRBHL, SFRBHI, WTVL, WTVI, WTVTL, WTVTI
ACS – Quoted Services	As Quoted, or AQMMBMR, AQPMCR, CHTARIFU, CHTARIFS, CHTARIFL, CHTARIFI, CHTSRAU, CHTSRAS, CHTSRAL, CHTSRAI, DEENAHU, DEENAHS, DEENAHL, DEENAHI, MOVEMTRU, MOVEMTRS, MOVEMTRL, MOVEMTRI, RMMTRU. RMMTRS, RMMTRL, RMMTRI MTRCKRDU, MTRCKRDS, MTRCKRDL, MTRCKRDI, MTRTESTU, MTRTESTS, MTRTESTL, MTRTESTI, MTTSTCTU, MTTSTCTS, MTTSTCTL, MTTSTCTI, OHUU, OHUS, OHUL, OHUI, POASVU, POASVS, POASVL, POASVI, POATVU, POATVS, POATVL, POATVI, REENAHS, REENAHL, REENAHI, REENAHU RMLDCRLU, RMLDCRLS, RMLDCRLL, RMLDCRLI, MTRREPU, MTRREPS, MTRREPL, MTRREPI, SPMTRRDU, SPMTRRDS, SPMTRRDL, SPMTRRDI, SFRAHU, SFRAHS, SFRAHL, SFRAHI
ACS – Street Lighting Services – East	East – Major, East – Minor
ACS – Street Lighting Services – West	West – Major, West – Minor
ACS – Street Lighting Services – Mount Isa	Mount Isa – Major, Mount Isa – Minor

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) 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 control mechanism determined by the AER in its Final Distribution Determination. Table 7.1 outlines the grouping based on the service provided and, for some 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:

- large customers requesting a new connection to the network or an upgrade to their existing connection
- street lighting customers requesting installation of a new street light, or gifting a new street light to Ergon Energy
- new service orders 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 the tariffs for Alternative Control Services are allocated to tariff classes in accordance with the AER's Classification of Services as set out in Appendix A of the Final Distribution 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 Appendix B of the AER's Final Distribution Determination because the tariffs within each tariff class are provided to customers that have 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" and the "Retailer Handbook" 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
- Street Lighting Services – based on the:
  - type of service requested by either a customer and/or retailer
  - customer's geographical location or pricing zone (i.e. East, West or Mount Isa).

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 also considers that 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) 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 and retailers 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 customer or the retailer.

A customer or retailer 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 customer or 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 customer, the customer is entitled to refer the matter to the AER for resolution via the dispute resolution process available under Part 10 of the Law.

The procedures a retailer or customer can follow if the customer objects to a proposed tariff class assignment or reassignment are set out in the publicly available “Price List for Alternative Control Services” and, for retailers, in the “Retailer Handbook”.

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 2013–14 year.

7.3 Fee Based and Quoted Services formula components

7.3.1 Changes in individual formula components for Fee Based and Quoted Services

As set out in section 18.3.5 of the Final Distribution Determination, Ergon Energy is required to set out the nature and extent of any variation to an individual formula component, on-cost or overhead rate applicable in the previous regulatory year that is above the indicative prices for Quoted Services and Fee Based

Services contained in the Final Distribution Determination. Where Ergon Energy varies a component, we must provide quantitative and qualitative information to support the variation.

Under the AER's Final Distribution Determination, Ergon Energy is able to recalculate escalators and overhead rates for each regulatory year. Changes to the nature of these components and quantitative information to support the calculation are set out below.

Labour escalators

The labour escalators contained in the AER's Final Distribution Determination were amended in 2011–12 to reflect the Tribunal's Determination on labour cost escalators made on 19 May 2011.

For the 2014–15 regulatory year, Ergon Energy has adjusted the nominal labour escalators by annual CPI data to March quarter 2014 as published by the ABS to develop prices for Fee Based Services and indicative prices for Quoted Services. This approach is the same as that used by Ergon Energy in 2013-14, which was accepted by the AER.

Materials escalators

Ergon Energy has adjusted the nominal materials escalators contained in the AER's Final Distribution Determination by annual CPI data to March quarter 2014 as published by the ABS to calculate indicative prices for Quoted Services in 2014–15.

There are no materials used in the provision of Fee Based Services.

This approach is the same as that used by Ergon Energy in 2013–14, which was accepted by the AER.

Other costs escalators

Ergon Energy has used the other costs escalators applied in the Tribunal's Determination on 'Other Costs'.

For the 2014–15 regulatory year, Ergon Energy has adjusted the other costs escalators by annual CPI data to March quarter 2014 as published by the ABS to calculate indicative prices for Quoted Services. Other costs do not apply in the provision of Fee Based Services.

This approach is the same as that used by Ergon Energy in 2013–14, which was accepted by the AER.

Overhead rates

Ergon Energy has recalculated our overhead rates. Consistent with our AER-approved Cost Allocation Method (CAM),[25] Ergon Energy uses the following methodology to calculate the overhead rate for our Fee Based and Quoted Services:

1. **Determine the total direct costs for each Line of Business (LOB) for the regulatory year**. At the start of the financial year, budget data is used to set costs expected to be directly attributable to business functions (LOB) within Ergon Energy in delivering our work plans. These costs include both capex and opex and are determined using an Activity Based Costing Method which maps and directly attributes expected costs of particular activities to categories of Services (distribution and unregulated) and LOB in the Chart of Accounts.
2. **Determine total shared costs (overheads) for the regulatory year**. Budget data is also 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

[25] Ergon Energy is currently reviewing our CAM in preparation for the next regulatory determination.

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.

3. **Allocation of total shared costs (overheads) between Ergon Energy Group districts**. 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). These include:

   - *Ergon Energy Queensland Pty Ltd* (EEQ) – subsidiary entity responsible for providing non-competing electricity retail services to non-market customers
   - *Ergon Energy Telecommunications Pty Ltd* – subsidiary entity and licensed telecommunications carrier providing wholesale high-speed data capacity to the Ergon Energy Group and external customers
   - *SPARQ Solutions Pty Ltd (SPARQ)* – 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.

   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.

4. **Allocation of shared costs between Ergon Energy LOB**. The total shared costs that are allocated to Ergon Energy are then further allocated between LOB on the following basis:

   - *Corporate Overheads* – costs are allocated to each LOB based on the ratio of direct costs for the LOB. That is, the total direct costs for each LOB (as described in step 1) are summed, and the relevant percentage of the total direct costs is determined for each LOB. These percentages are then used to fully allocate the shared corporate costs across each LOB.
   - *Operational Overheads* – costs are also allocated to LOB based on a ratio of direct costs. However, as some of the operational business units do not take part in some LOB, the shared cost percentage rates are 'grossed up' in order to fully allocate the costs over applicable LOB. That is, the direct cost percentages for each LOB that the business unit takes part in are summed, to determine a proportion of the total direct costs that are attributable to the business unit. The direct cost percentage for each LOB is then divided by the total proportion of direct costs for the business unit to determine a percentage to fully allocate the shared operational costs over each applicable LOB.

5. **Calculate the overhead rate for each LOB**. The total overhead rate for each LOB is then calculated by summing the total allocated shared costs for each LOB, and expressing this as a percentage of total costs for each LOB (i.e. total costs being the sum of direct costs and overhead costs for each LOB).

6. **Select appropriate overhead rate**. The overhead rate used by Ergon Energy for our Fee Based and Quoted Services is the calculated overhead rate for the LOB that represents the work

undertaken and Activity in the provision of the particular service in the Chart of Accounts. For example:

- The Large Customer Connection service is mapped to the 'Connection Services Large' Activity and attributed to the Regulated Capex LOB in the Chart of Accounts. This means the overhead rate used in the Quoted Services formula for Large Customer Connections will be the annual Regulated Capex overhead rate calculated by Ergon Energy in accordance with the CAM.
- Street Lighting Service 1 (i.e. relating to provision of new street lighting assets) is mapped to the 'Other Customer Requested Works' and attributed to the Regulated Capex LOB in the Chart of Accounts. This means the overhead rate used in the Quoted Services formula to calculate the incremental cost difference between the provision of standard and non-standard street lighting assets will be the annual Regulated Capex overhead rate calculated by Ergon Energy in accordance with the CAM.
- All other Fee Based and Quoted Services are mapped to a range of activities attributed to the Customer Services LOB in the Chart of Accounts. This means the overhead rate used in the formula to calculate the tariffs to be levied for these Fee Based and Quoted Services will be the annual Customer Services overhead rate calculated by Ergon Energy in accordance with the CAM.

Ergon Energy's 2014–15 overhead rate calculation is provided in Appendix 5.

7.3.2 Changes in methodology employed to derive formula components

As set out in section 18.3.5 of the Final Distribution Determination, Ergon Energy is required to set out the nature and extent of any variation or adjustment to the methodology employed to derive a formula component escalator, on-cost or overhead rate.

Under the AER's Final Distribution Determination, Ergon Energy is able to recalculate labour, materials and other costs escalators, and overhead rates for each regulatory year. Ergon Energy confirms that we have not varied or adjusted the methodology employed to derive these components. Overhead rates are calculated in accordance with the AER-approved CAM.

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 2014–15 tariffs for Alternative Control Services are set out in Appendix 4.

7.5 Volume and revenue for 2012–13

7.5.1 Fee Based and Quoted Services

As outlined in section 18.3.5 of the Final Distribution Determination, the AER requires Ergon Energy to set out the volume of Fee Based and Quoted Services provided and the revenues recovered from the provision of each individual Fee Based and Quoted Service in the preceding regulatory year.

Appendix 6 sets out the actual volumes and revenues for the Fee Based and Quoted Services provided by Ergon Energy in 2012–13.

7.5.2 ACS – Street Lighting Services

Section 17.3.3 of the AER's Final Distribution Determination requires Ergon Energy to provide information on the revenues collected from the provision of each ACS – Street Lighting Service in the preceding regulatory year.

Appendix 6 sets out the actual revenues for the ACS – Street Lighting Services provided by Ergon Energy in 2012–13.

7.6 Avoidable and stand alone costs

As noted in Section 6.8, 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 6.8, Ergon Energy has set out below our approach to determining these costs for our Fee Based and Quoted Services, and ACS – Street Lighting Services.

7.6.1 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.

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). Given that Ergon Energy provides more than one Alternative Control Service tariff class, the allocation of shared assets such as depots and vehicles are shared between all Alternative Control Service tariff classes. This means that the revenue received from one Alternative Control Service tariff class will be less 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 Alternative Control Services are labour costs charged on an hourly basis and materials consumed during the course of providing the service. 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.

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

7.6.2 ACS – Street Lighting Services

The prices for ACS – Street Lighting Services have been developed by allocating the approved ARR to the East, West and Mount Isa Zones for ACS – Street Lighting Services. Given that Ergon Energy has proposed one street lighting tariff class for each of these zones, the revenue expected to be recovered from each tariff class will be equal to the allocation of the ARR for ACS – Street Lighting Services for that zone. It will not exceed the stand alone cost. The expected revenue therefore lies on the stand alone cost, and is compliant with clause 6.18.5(a)(1) of the NER.

The avoidable cost for ACS – Street Lighting Services is equal to the cost which would be avoided by Ergon Energy not providing a particular tariff class of ACS – Street Lighting Services. For example, if Ergon Energy was to cease providing street lighting services in our West Zone, we would avoid the allocated ARR for ACS – Street Lighting Services in that zone, comprising the ROA, depreciation and direct opex on street lighting assets. However, we would not avoid shared costs (overheads) which provide services to other Alternative Control Service tariff classes. The avoidable cost will therefore be less than the stand alone cost.

Given that expected revenue lies on the stand alone cost, and the avoidable cost is less than the stand alone cost, the expected revenue complies with clause 6.18.5(a) of the NER.

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

The NER require 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 and ACS – Street Lighting 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 Section 4 is largely determined through the control mechanism established by the AER in its Final Distribution 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 (leaving aside street lighting) 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.

7.8 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.

Since the current regulatory control period ends on 30 June 2015, we are not required to provide expected price trends as part of this Pricing Proposal. However, at a high level, Ergon Energy is committed to improving the affordability of electricity for our customers.

Our Regulatory Proposal will set out indicative prices we propose for Alternative Control Services for the 2015–20 regulatory control period. It will be submitted to the AER on 31 October 2014 and will be available on our website at www.ergon.com.au/futureinvestment. The AER will assess our Regulatory Proposal and will release a Distribution Determination which ultimately sets the revenue or prices we are allowed to collect or charge for our distribution services in the next regulatory control period.

It is important to note that, due to changes in the classification of distribution services, there may be additional Alternative Control Services in the next regulatory control period.

7.9 Procurement processes and procedures for Quoted Services

On 19 May 2011, the Tribunal varied the AER's Final Distribution Determination to allow Ergon Energy to charge customers other one-off costs we incur relating to the delivery of a Quoted Service. As part of this decision, the Tribunal specified that Ergon Energy must report on any departures from our procurement processes and procedures in delivering Quoted Services that include other costs, as part of our Annual Pricing Proposal to the AER.

Ergon Energy provided detailed explanations of our procurement process and procedures to the AER as part of the Tribunal review process in 2010. In September 2013, Ergon Energy reviewed our Sustainable Procurement Policy and made the following changes:

- procurement monetary caps have been amended to include the range of $20,000 to $100,000, with our Strategic Procurement Group being responsible for expenditure in this range
- corporate card limits have been raised from $1,000 to $2,000.

Ergon Energy also notes that the Queensland Procurement Policy (formerly, State Purchasing Policy) no longer applies to us, our subsidiaries and our controlled entities.[26] Our current Sustainable Procurement Policy and business rules are closely aligned with the Queensland Procurement Policy. We do not intend to dilute these documents following this revocation.

[26] Queensland Government Gazette No.27, 7 February 2014, p133.

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 Section 6.9, 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 capacity, demand and usage 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 2.3, 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 closely 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 2014–15. 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 2014–15, in line with the methodology set out in this Pricing Proposal.

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.

At the time of preparing this Pricing Proposal, the impacts of the Queensland Electricity Sector Reform are not known. Accordingly, Ergon Energy may also need to adjust tariffs during the 2014–15 regulatory year as a result of the Queensland Electricity Sector Reform as discussed in Section 2.2.2 above. If this occurs, Ergon Energy will inform the AER.

There are no other variations or adjustments proposed to be made to remaining tariffs during the course of the next regulatory year.[27]

[27] The exception being the maximum price caps under Schedule 8 of the *Electricity Regulation 2006* discussed in Section 4.3 of this Pricing Proposal.

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.

There are no fundamental changes proposed to tariff classes, tariffs and tariff setting processes for our Alternative Control Services for 2014–15, in comparison to those already approved by the AER as being compliant with the NER and the Final Distribution Determination in the 2013–14 regulatory year.

However, as noted in Section 2.3, Ergon Energy is proposing a number of changes to our network tariff structures from 1 July 2014 for our Standard Control Services. These changes are set out in Table 8.1 and described in more detail in the sections below.

Table 8.1: Summary of network tariff changes in 2014–15

Network user group	Tariff changes
ICC	▪ Change to the existing capacity charge and the anytime maximum demand charge. The charging parameters will now be denominated in kVA rather than kW.
CAC	▪ No change for 2014–15.
SAC >100 MWh p.a.	▪ No changes to the underlying structures of the tariffs but we have commenced rebalancing toward a more cost reflective demand charge (slight reduction), which is offset by an increase in the fixed component. ▪ Revenue recovered through the minimum monthly demand charge in 2013–14 has been incorporated into the fixed charge in 2014–15. ▪ Calculation of the monthly demand charges has changed and the actual demand charge ($/kW) only applies to demand above the relevant threshold applicable to the customer's tariff.
SAC <100 MWh p.a.	Replacement of consumption-based segmentation (i.e. Volume Large and Small) with segmentation based on the type of customer (i.e. Residential and Business). <u>Residential customers</u> ▪ Introduction of a new default tariff, which comprises a fixed charge and inclining block energy tariff. This tariff replaces the 2013–14 default fixed charge and flat anytime energy tariff structure. ▪ Introduction of a new, optional seasonal TOU energy tariff. <u>Business customers</u> ▪ Introduction of a new default tariff, which comprises a fixed charge and inclining block energy tariff. This tariff replaces the 2013–14 default fixed charge and flat anytime energy tariff structure. ▪ Introduction of a new, optional seasonal TOU energy tariff. <u>Controlled supplies</u> ▪ No change for 2014–15. <u>Unmetered</u> ▪ No change for 2014–15.
EG	▪ No change for 2014–15 (unless the EG has a load side, in which case refer to the applicable changes for ICC, CAC and SAC customers above).

8.3.1 Changes to ICC network tariffs

The key change for ICC tariffs in 2014–15 is a move from a kW basis for the two demand-related charges (capacity and actual demand) to a kVA basis for the DUOS and TUOS components.

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.

Our network charges are currently mispricing the network impact of a premise with a low or poor power factor. Our aim is to use tariffs to give better pricing signals for our larger customers (i.e. signals that reflect the additional capacity that we must supply to a customer associated with lower power factor). This change is relatively consistent with the approach taken by Energex and network service providers in other jurisdictions and is able to be implemented from 1 July 2014 given the functionality already exists to record kVA for this customer class.

Figure 8.1: Changes in distribution charges for very large energy users in 2014–15

The approach to the allocation of TUOS to individual customers has not changed. However, the way TUOS is recovered has been aligned with the changes to DUOS to minimise network tariff and billing complexity.

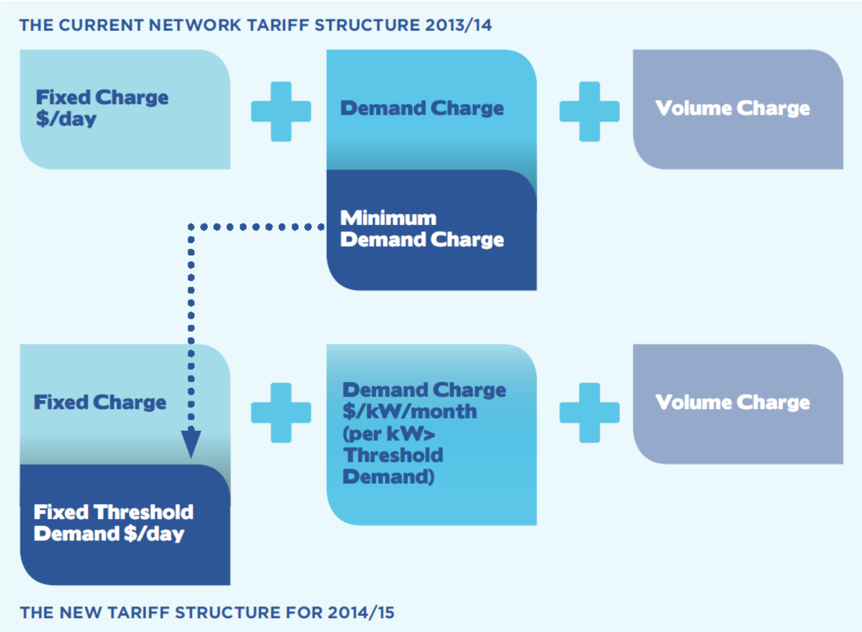
This change to kVA has been reflected in the tariff charging parameter demand denomination for ICCs, as detailed in Appendix 2.

8.3.2 Changes to SAC >100 MWh p.a. tariffs

While there will be no structural change to these tariffs, in 2014–15, we will be taking two steps to lay the foundations needed to introduce time-based demand tariffs in the future:

1. **A move to the fixed charge** – the minimum monthly demand charge currently incorporated in this tariff structure will be removed. In its place, the revenue we currently collect through the minimum demand charge will be incorporated into the fixed charge. To avoid over-recovery of revenue, the existing demand charge will only apply to the demand in excess of a threshold set at the minimum chargeable demand level of the current tariff.
2. **Rebalancing usage charges** – we are lowering the rate per kW for the demand charge to offset an increase in the fixed charge. This is about providing more cost reflective price signals, which are consistent with the BCS for incremental demand on the network. In applying this same principle across other tariff classes, some will see the demand recovery component being increased as we move forward.

Figure 8.2: Changes to distribution charges for SACs >100MWh p.a.



The actual demand charge will be applied to the kW amount by which a customer's actual monthly maximum demand is greater than the demand threshold applicable to the customer's network tariff. The formula that will be applied is:

$$\boldsymbol{Actual\ demand\ charge} = (\boldsymbol{Metered\ demand} - \boldsymbol{Threshold\ demand}) \times \boldsymbol{Actual\ demand\ charge\ rate}$$

Where the monthly metered maximum demand is less than the demand threshold, the chargeable demand is set to zero and no demand charge is payable for that month. The threshold demand applicable to each network charge category is shown in the table below.

Table 8.2: Threshold demands

Network charge category	Threshold demand
Demand High Voltage	400 kW
Demand Large	400 kW
Demand Medium	120 kW
Demand Small	30 kW

With respect to TUOS, complementary changes have been made so that the same demand threshold calculation mechanism applies for TUOS charges.

These changes have been reflected in the tariff charging parameters and rates for SACs >100 MWh p.a., as detailed in Appendix 1.

8.3.3 Changes to SAC <100 MWh p.a. tariffs

Ergon Energy is starting on a path to move tariffs for customers in this class away from 'energy charges' to an appropriate balance between fixed and demand based charges. To start this journey, we are introducing two new tariff structures for our small customers in 2014–15. At the same time, we are moving to reduce our reliance on charges based on the volume of electricity used.

The changes in 2014–15 include:

- classifying customers as either residential or business
- adopting an IBT as the standard default tariff and increasing the fixed charge
- offering greater choice with an optional seasonal TOU tariff.

The structure of our off-peak controlled network tariffs will not change in 2014–15. Further, the TUOS volume component will effectively remain as a flat rate for all IBT and TOU tariffs (i.e. same TUOS rate applied in each tariff block or time period). This means the rate differentiation between the blocks (IBT) or the time periods (TOU) is solely determined by the DUOS component of the tariff.

The below changes are incorporated in the tariff structures, charging parameters and rates for SACs <100 MWh p.a., as illustrated in Appendix 1. It is important to note that the IBT and TOU tariffs will only be available to customers on a market contract or offer. Regulatory arrangements in Queensland mean that these tariffs will not be available to EEQ retail customers on the regulated retail electricity prices (or Notified Prices) which are determined by the QCA.

Further information on the methodology for developing the IBT and TOU tariffs is provided in Energeia's "Development of New Cost Reflective Tariffs for Standard Asset Customers – Small" report (Attachment 3).

Classifying customers as either residential or business

The current distinction in tariffs in this class between Volume Small (less than 26 MWh p.a.) and Volume Large (more than 26 MWh p.a. and less than 100 MWh p.a.) customers will be replaced with tariffs for residential and business tariffs. This will ensure tariffs reflect residential and business customers' different load shapes. Load shapes refer to the amount of electricity customers use at different times of the day.

In the case of both the default and optional tariffs, there are differences between residential and business customers. For IBT, the primary structural difference is in the block sizes. For TOU, there are differences in the Peak and Shoulder periods which also impact Off-Peak times.

In establishing different tariffs for business and residential SACs <100 MWh p.a., Ergon Energy has also sought to minimise shifts from the 2013–14 parity between business and residential customers to a minimum for most SACs <100 MWh p.a.

Adopting an inclining block structure for the volume component of the default tariff

The IBT is a transitional step in updating the current tariff structure. It will go some way to better reflect costs without requiring metering changes at the premises.

Each block has a different rate applied to energy consumed within the band. For the purposes of IBT network billing, the energy (kWh) assigned to each block during a meter reading period are pro-rated back to a daily equivalent with the tariff applying on a daily basis.

The tariff charging parameters have also been re-weighted to increase alignment between revenue recovery and distribution cost structure, through rebalancing from volume charges to fixed charges. However, as the variable rates go up in 'blocks', we can reduce the impact of increasing the fixed charge on customers with a low consumption by offering a reduced rate for the first 'block' of consumption.

IBT Business tariff

Ergon Energy's IBT Business tariff has three inclining blocks.

Respective rates for each of Ergon Energy's consumption blocks apply only to consumption in the block. The consumption blocks for the IBT Business tariffs (presented on an annualised basis) are as follows:

Block 1	0 – 1,000 kWh p.a.
Block 2	1,000 kWh p.a. – 20,000 kWh p.a.
Block 3	>20,000 kWh p.a.

The IBT Business tariff will be the default primary network tariff applying to all business SACs <100 MWh p.a. from 1 July 2014. This means all business customers currently on the Volume Small and Volume Large network tariffs will transition to the IBT Business tariff from 1 July 2014.

The IBT Business tariffs will incorporate the following charging parameters:

- a fixed charge ($/day)
- volume charges ($/kWh) (specific rates applicable to Block 1, Block 2 and Block 3).

IBT Residential tariff

Ergon Energy's IBT Residential tariff has three inclining blocks.

Respective rates for each of Ergon Energy's consumption blocks apply only to consumption in the block. The consumption blocks for the IBT Residential tariffs (presented on an annualised basis) are as follows:

Block 1	0 – 1,000 kWh p.a.
Block 2	1,000 kWh p.a. – 6,000 kWh p.a.
Block 3	>6,000 kWh p.a.

The IBT Residential tariff will be the default primary network tariff applying to all residential SACs <100 MWh p.a. from 1 July 2014. This means all residential customers currently on the Volume Small and Volume Large network tariffs will transition to the IBT Residential tariff from 1 July 2014.

The IBT Residential tariffs will incorporate the following charging parameters:

- a fixed charge ($/day)
- volume charges ($/kWh) (specific rates applicable to Block 1, Block 2 and Block 3).

Offering greater choice with an optional seasonal TOU tariff

TOU network tariffs will also be introduced as an option in 2014–15. Similar tariffs are currently used elsewhere in Australia. However, our offer includes seasonal and time-of-day dimensions that mirror regional Queensland's unique seasonal loads.

Under a TOU tariff structure, customers are provided visibility of the higher costs associated with consumption in Peak and Shoulder periods compared to Off-Peak times (when prices are significantly lower). The three-part volume-based TOU tariffs for business customers and residential customers are aimed at greater cost reflectivity and customer choice. These TOU tariffs have both seasonal and time of day dimensions associated with the peak charges, based on analysis of regional Queensland's business and residential load profiles across the different seasons of the year.

TOU Business tariff

Ergon Energy's TOU Business tariff adopts a three-part seasonal TOU tariff structure.

The following time periods apply for TOU Business tariffs:

Peak	11:30am to 5:30pm on Summer weekdays
Shoulder	10:00am to 11:30am and 5:30pm to 8:00pm on Summer weekdays
Off-Peak	All other times

Note: Summer is defined as the months of December, January and February.

The TOU tariffs are optional for business SACs <100 MWh p.a. from 1 July 2014. A customer (or their retailer) must request a tariff change to opt in to these tariffs. This request will be subject to metering considerations.

The TOU Business tariffs will incorporate the following charging parameters:

- a fixed charge ($/day)
- volume charges ($/kWh), which will be based on the above TOU structure (i.e. Peak, Shoulder and Off-Peak time periods).

TOU Residential tariff

Ergon Energy's TOU Residential tariff adopts a three-part seasonal TOU tariff structure.

The following time periods apply for TOU Residential tariffs:

Peak	4:30pm to 9:00pm on Summer weekdays
Shoulder	3:00pm to 4:30pm and 9:00pm to 9:30pm on Summer weekdays, and 3:00pm to 9:30pm on Summer weekends
Off-Peak	All other times

Note: Summer is defined as the months of December, January and February.

The TOU tariffs are optional for residential SACs <100 MWh p.a. from 1 July 2014. A customer (or their retailer) must request a tariff change to opt in to these tariffs. This request will be subject to metering considerations.

The TOU Residential tariffs will incorporate the following charging parameters:

- a fixed charge ($/day)
- volume charges ($/kWh), which will be based on the above TOU structure.

8.3.4 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 (refer Figure 8.3). This included:

- media advertising
- website notification
- direct written correspondence and emails
- presentations and discussions at seven regional Queensland public forums facilitated by the QCA

- discussion with our own Customer Council
- other face-to-face discussions with particular interest groups.

The regional Queensland forums, in particular, were an invaluable tool, providing clear feedback on our proposed changes.

Figure 8.3: Summary of stakeholder engagement activities

Jan 2013
- Ernst and Young Network Tariff Review - possible tariff development options commissioned for public release to independently inform customers and stakeholders around network tariffs to assist understanding and consultation response formulation

Jun 2013
- Initial public consultation - extensively promoted through multiple channels to stakeholders and customers
- 40 formal responses received

Dec 2013
- Responses to initial consultation reviewed, tariffs analysis and development undertaken
- Revised strategy, and indicative network tariffs and structures for 2014-15 were released for the second round of formal public consultation

Apr 2014
- Responses from both rounds of consultation, regional Queensland QCA tariff forums and further stakeholder discussion were incorporated into revised and improved tariff structures (particularly for residential and small business customers)
- Indicative network tariffs, consultation responses (and summaries), and customer brochures published on Ergon Energy's website

Apr 2014
- Current activities include specific engagement with ICCs, retailers and respondents to the second round of consultation, and follow-up of customer commitments from the regional Queensland QCA forums

Further information on this process, including submissions received across our two stage consultation process, is provided on our website.[28] In addition to customer and stakeholder input, we have performed our own detailed analysis and drawn upon external economic and tariff expertise.

Through this process, Ergon Energy has made progressive changes to the initial indicative network tariffs described in our June 2013 consultation papers and the indicative network tariffs published on our website in December 2013.[29] In particular, we have focused on limiting and managing the quantum of the impact of tariff structural changes on individual customers.

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.

The impact of tariff structural change in 2014–15 we refer to is the impact on customers from the new tariff structures, assuming the normal revenue cap increases in 2014–15 had already been factored into the existing tariffs.

[28] See www.ergon.com.au/futurenetworktariffs.
[29] See www.ergon.com.au/futurenetworktariffs.

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

For our ICCs and SACs >100 MWh p.a., Ergon Energy has limited the maximum adverse individual customer impact on DUOS charges in 2014–15 to no more than 10 per cent

The limitations on individual customer impacts described above typically bind on customers with outlier load characteristics. Therefore, these limiting outcomes are not what the great majority of customers experience or are close to experiencing in 2014–15. Also, no upside limit was applied with respect to customers whose load profile benefits from the tariff changes.

For ICCs, the conversion to kVA is expected to lead to 47 per cent of customers experiencing an increase in overall DUOS charges, 8 per cent having no change and 45 per cent receiving a decrease. The 10 per cent constraint was not binding on implementation of the 2014–15 change, with the maximum customer DUOS increase being estimated at 7.4 per cent and only four customers having an increase above 5 per cent. When assessed at the Network Use of System level (i.e. DUOS plus TUOS), only one customer is estimated to have an increase higher than 5 per cent. It is noted that by shifting to a kVA tariff, customers now have access to a tariff which they can influence through changing their power factor.

In reviewing changes to the 2014–15 rates for SACs >100 MWh p.a., large increases in the quantum of the fixed charge compared with 2013–14 rates are clearly evident. This increase is offset by the application of the threshold demand to metered monthly demand to calculate (and effectively reduce compared to 2013–14) the monthly demand charge payable. The constraint applied to SACs >100 MWh p.a. means that virtually no customers experience an increase of more than 5 per cent and, overall, more than 55 per cent of customers would experience either a reduction or an increase of less than 1 per cent.

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

Similarly, we have aimed to limit the direct cost impact of the tariff changes on our SACs <100 MWh p.a. to less than 10 per cent of the network charge. Where increases as a result of the changes could be more than 10 per cent, the increase has been limited through a cap linked to the fixed charge component ($150 per annum) for each NMI.

With respect to the increase in fixed charge of $150, the introduction of the IBT was crucial to being able to offset the impact of this change for small consumption customers. Following responses to both rounds of consultation, significant changes were made to further reduce the number of customers impacted and the cost impact of the change to fixed charges by setting the IBT DUOS energy rate at zero for the first 1000 kWh (i.e. Block 1) in the East and Mount Isa zones, and 7 cents per kWh in the West Zone. Further, the proposed increase in the fixed charge for business customers was reduced from $300 per annum to $150, to align with the residential tariffs. The IBT structure and the first block rate effectively more than offset the increase in the fixed charge for customers consuming over 1000 kWh per annum (less than 3 kWh per day).

As a result, over three quarters of residential customers are expected to have a (small) reduction in their network charges on the IBT compared with retaining the existing structure in 2014–15. Meanwhile, 57 per cent of East business customers, 43 per cent of West business customers and 34 per cent of Mount Isa business customers are likely to have a reduction in their network charges on the IBT compared with retaining the existing structure in 2014–15. The lower percentages for the business customer segment reflect a distribution of consumption that has a greater proportion of both very low and high consumption NMIs, compared to the residential segment.

Customers that are expected to experience increases are those with low consumption (less than 1,000 kWh) and larger consumption. The relationship between the TOU tariff and the IBT is such that (assuming a typical load profile for the customer class), customers with larger consumption levels are better off on the TOU compared to either the IBT or the existing structure.

For small consumption customers, the IBT structure requires only minimal consumption by a customer at a NMI to offset the change to the fixed charge. A customer consuming 3 kWh per day will be better off on the IBT network tariff than if the current structure was maintained. Given a typical residential fridge will consume 1–2 kWh per day, the impacts are more likely to affect temporal accommodation (e.g. holiday homes) or customers with substituted energy (e.g. controlled load and solar PV etc.). Again, we have sought to cap structural change increases to $150 per annum for individual residential customers.

Following Ergon Energy's responses to customer and stakeholder feedback, the network tariffs in this Pricing Proposal are now considered to provide an improved balance between laying the foundation for progressive development of cost reflective tariffs in 2014–15, while limiting the impact on individual customers.

Further information on customer impacts is contained in the "Customer Impact Analysis" report which has been prepared by Frontier Economics (Attachment 4).

8.3.5 Other changes compared to 2013–14 Pricing Proposal

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

- changing the approach to the calculation of avoidable and stand alone costs (refer to Section 6.8)
- referencing the BCS in the setting of rates to apply to the new tariff structure parameters and rebalancing of existing parameters (refer to Section 6.9)
- considering the impact on transaction costs (refer to Section 6.10)
- considering the likelihood and ability of customers to respond to price signals (refer to Section 6.11)
- revising the granularity of our SAC <100 MWh p.a. forecasting to support rate development for SAC <100 MWh p.a. tariffs and appraisal of take-up rates of optional TOU tariffs (refer to Section 8.4).

8.3.6 Compliance with regulatory obligations

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

It is important to note that there is no specific compliance obligation directly addressing changes to individual tariff components. Nevertheless, the proposed network tariff changes do affect the underlying information used to demonstrate compliance with some obligations and NER requirements.

Clauses that relate to tariff classes (not individual tariffs) have not been affected. This is because:

- no changes are proposed to tariff classes in comparison to what was approved in the previous regulatory year. Ergon Energy's proposed changes are isolated to network tariffs within the respective tariff classes.
- the manner in which customers are assigned to tariff classes has not changed. Customers with similar usage and connection profiles will continue to be treated on a similar (and equal) basis under the new tariff structures (refer to Section 6.2).

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 2005–2010 regulatory control period and the current regulatory control period. The forecasts developed by this methodology during this regulatory control period were accepted by the AER in the relevant years.

For the purposes of supporting the new SAC <100 MWh p.a. IBT and TOU tariff structures from 1 July 2014, additional granularity of these historically derived forecasts has also been undertaken. The basis of the historic forecasts in terms of tariff class customer numbers and energy has not changed. In 2013–14, the SAC <100 MWh p.a. tariff class was split on the basis of Volume Small and Volume Large. For 2014–15, the same total SAC <100 MWh p.a. cohort has been split into Business and Residential segments.

Forecasts were then 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).

As SACs <100 MWh p.a. will have the option of either the IBT (default) or the TOU tariff, and the net outcome would have different overall revenue implications, a forecast of the adoption of each tariff was required. Ergon Energy has assumed that there will be no customer churn from the default IBT to the optional TOU tariff in 2014–15. This is because:

- churn from the default IBT to the optional TOU tariff is only likely to be considered by retailers and customers who are in the market (currently less than one per cent of all customers). Our non-market SACs <100 MWh p.a. currently access regulated retail electricity prices (Notified Prices) that are based on Energex's network costs or non-cost reflective transitional tariffs. As such, they do not have visibility of our network tariff pricing signals.
- only customers with larger consumption are likely to benefit from the adoption of TOU in 2014–15
- 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.

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 and losses of load.

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 2014. 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

Standard Control Service network tariffs for SACs, and accompanying explanatory notes, are set out below. Site specific network tariffs for ICCs, CACs and EGs 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.

TARIFFS APPLYING TO STANDARD ASSET CUSTOMERS – LARGE (>100 MWh per annum) GST Exclusive										
Tariff Description	Network Tariff Code	Threshold Above Which Demand Charge Applies	Default Distribution Loss Factor		Distribution Use Of System (DUOS)			Transmission Use Of System (TUOS)		
					Fixed Charge (NDFC)	Actual Demand Charge (NDADC)	Volume Charge (NDVC)	Fixed Charge (NTFC)	Capacity Charge (NTCC)	Volume Charge (NTVC)
		kilowatts	Value	Code	dollars per day	dollars per kilowatt per month	dollars per kilowatt hour	dollars per day	dollars per kilowatt per month	dollars per kilowatt hour
Demand High Voltage	EDHTT1	400	1.034	GEHL	$341.824	$20.965	$0.00553	$17.298	$0.959	$0.01110
	EDHTT2	400	1.034	GEHL	$341.824	$20.965	$0.00553	$33.843	$2.275	$0.01330
	EDHTT3	400	1.034	GEHL	$341.824	$20.965	$0.00553	$63.438	$4.532	$0.01668
	WDHTT1	400	1.127	GWHL	$800.148	$50.000	$0.01526	$17.298	$0.959	$0.01110
	WDHTT2	400	1.127	GWHL	$800.148	$50.000	$0.01526	$33.843	$2.275	$0.01330
	WDHTT3	400	1.127	GWHL	$800.148	$50.000	$0.01526	$63.438	$4.532	$0.01668
	MIDHT	400	1.035	GMHL	POA	POA	POA	$8.128	$0.449	$0.00047
Demand Large	EDLTT1	400	1.094	GELL	$419.276	$28.780	$0.00553	$17.298	$0.959	$0.01110
	EDLTT2	400	1.094	GELL	$419.276	$28.780	$0.00553	$33.843	$2.275	$0.01330
	EDLTT3	400	1.094	GELL	$419.276	$28.780	$0.00553	$63.438	$4.532	$0.01668
	WDLTT1	400	1.184	GWLL	$1,254.653	$90.000	$0.00960	$17.298	$0.959	$0.01110
	WDLTT2	400	1.184	GWLL	$1,254.653	$90.000	$0.00960	$33.843	$2.275	$0.01330
	WDLTT3	400	1.184	GWLL	$1,254.653	$90.000	$0.00960	$63.438	$4.532	$0.01668
	MIDLT	400	1.060	GMLL	$262.385	$15.000	$0.00493	$8.128	$0.449	$0.00047
Demand Medium	EDMTT1	120	1.094	GELL	$140.448	$30.076	$0.00553	$8.476	$0.959	$0.01110
	EDMTT2	120	1.094	GELL	$140.448	$30.076	$0.00553	$12.915	$2.275	$0.01330
	EDMTT3	120	1.094	GELL	$140.448	$30.076	$0.00553	$21.747	$4.532	$0.01668
	WDMTT1	120	1.184	GWLL	$394.216	$92.000	$0.01309	$8.476	$0.959	$0.01110
	WDMTT2	120	1.184	GWLL	$394.216	$92.000	$0.01309	$12.915	$2.275	$0.01330
	WDMTT3	120	1.184	GWLL	$394.216	$92.000	$0.01309	$21.747	$4.532	$0.01668
	MIDMT	120	1.060	GMLL	$92.106	$18.284	$0.00493	$3.997	$0.449	$0.00047

TARIFFS APPLYING TO STANDARD ASSET CUSTOMERS – LARGE (>100 MWh per annum) GST Exclusive										
Tariff Description	Network Tariff Code	Threshold Above Which Demand Charge Applies	Default Distribution Loss Factor		Distribution Use Of System (DUOS)			Transmission Use Of System (TUOS)		
					Fixed Charge (NDFC)	Actual Demand Charge (NDADC)	Volume Charge (NDVC)	Fixed Charge (NTFC)	Capacity Charge (NTCC)	Volume Charge (NTVC)
		kilowatts	Value	Code	dollars per day	dollars per kilowatt per month	dollars per kilowatt hour	dollars per day	dollars per kilowatt per month	dollars per kilowatt hour
Demand Small	EDSTT1	30	1.094	GELL	$38.728	$33.630	$0.00553	$5.640	$0.959	$0.01110
	EDSTT2	30	1.094	GELL	$38.728	$33.630	$0.00553	$6.188	$2.275	$0.01330
	EDSTT3	30	1.094	GELL	$38.728	$33.630	$0.00553	$8.347	$4.532	$0.01668
	WDSTT1	30	1.184	GWLL	$107.011	$95.846	$0.01526	$5.640	$0.959	$0.01110
	WDSTT2	30	1.184	GWLL	$107.011	$95.846	$0.01526	$6.188	$2.275	$0.01330
	WDSTT3	30	1.184	GWLL	$107.011	$95.846	$0.01526	$8.347	$4.532	$0.01668
	MIDST	30	1.060	GMLL	$25.900	$21.664	$0.00493	$2.670	$0.449	$0.00047

2014-15 Rates TARIFFS APPLYING TO STANDARD ASSET CUSTOMERS – SMALL (<100 MWh per annum) INCLINING BLOCK TARIFF (IBT) GST Exclusive											
Tariff Description	Network Tariff Code	Threshold Above Which Demand Charge Applies	Default Distribution Loss Factor		Distribution Use Of System (DUOS)				Transmission Use Of System (TUOS)		
					Fixed Charge (NDFC)	Volume Charge (NDVC)					
						Block 1	Block 2	Block 3	Fixed Charge (NTFC)	Capacity Charge (NTCC)	Volume Charge (NTVC)
		kilowatts	Value	Code	dollars per day	dollars per kilowatt hour	dollars per kilowatt hour	dollars per kilowatt hour	dollars per day	dollars per kilowatt per month	dollars per kilowatt hour
IBT Residential	ERIBT1		1.094	GELL	$1.525	$0.00000	$0.15314	$0.16314	$0.121		$0.01110
	ERIBT2		1.094	GELL	$1.525	$0.00000	$0.15314	$0.16314	$0.218		$0.01330
	ERIBT3		1.094	GELL	$1.525	$0.00000	$0.15314	$0.16314	$0.297		$0.01668
	WRIBT1		1.184	GWLL	$2.325	$0.07000	$0.44971	$0.45971	$0.121		$0.01110
	WRIBT2		1.184	GWLL	$2.325	$0.07000	$0.44971	$0.45971	$0.218		$0.01330
	WRIBT3		1.184	GWLL	$2.325	$0.07000	$0.44971	$0.45971	$0.297		$0.01668
	MIRIB		1.060	GMLL	$1.545	$0.00000	$0.07771	$0.08771	$0.107		$0.00047
IBT Business	EBIBT1		1.094	GELL	$1.525	$0.00000	$0.15383	$0.16383	$0.121		$0.01110
	EBIBT2		1.094	GELL	$1.525	$0.00000	$0.15383	$0.16383	$0.218		$0.01330
	EBIBT3		1.094	GELL	$1.525	$0.00000	$0.15383	$0.16383	$0.297		$0.01668
	WBIBT1		1.184	GWLL	$2.295	$0.07000	$0.45571	$0.46571	$0.121		$0.01110
	WBIBT2		1.184	GWLL	$2.295	$0.07000	$0.45571	$0.46571	$0.218		$0.01330
	WBIBT3		1.184	GWLL	$2.295	$0.07000	$0.45571	$0.46571	$0.297		$0.01668
	MIBIB		1.060	GMLL	$1.545	$0.00000	$0.08138	$0.09978	$0.107		$0.00047

2014-15 Rates
TARIFFS APPLYING TO STANDARD ASSET CUSTOMERS – SMALL (<100 MWh per annum)
TIME-OF-USE (TOU)
GST Exclusive

Tariff Description	Network Tariff Code	Threshold Above Which Demand Charge Applies	Default Distribution Loss Factor		Distribution Use Of System (DUOS)				Transmission Use Of System (TUOS)		
					Fixed Charge (NDFC)	Volume Charge (NDVC)					
						Peak	Shoulder	Off-Peak	Fixed Charge (NTFC)	Capacity Charge (NTCC)	Volume Charge (NTVC)
		kilowatts	Value	Code	dollars per day	dollars per kilowatt hour	dollars per kilowatt hour	dollars per kilowatt hour	dollars per day	dollars per kilowatt per month	dollars per kilowatt hour
TOU Residential	ERTOUT1		1.094	GELL	$1.525	$0.55194	$0.26664	$0.09568	$0.121		$0.01110
	ERTOUT2		1.094	GELL	$1.525	$0.55194	$0.26664	$0.09568	$0.218		$0.01330
	ERTOUT3		1.094	GELL	$1.525	$0.55194	$0.26664	$0.09568	$0.297		$0.01668
	WRTOUT1		1.184	GWLL	$2.325	$1.51214	$0.96023	$0.31361	$0.121		$0.01110
	WRTOUT2		1.184	GWLL	$2.325	$1.51214	$0.96023	$0.31361	$0.218		$0.01330
	WRTOUT3		1.184	GWLL	$2.325	$1.51214	$0.96023	$0.31361	$0.297		$0.01668
	MIRTOU		1.060	GMLL	$1.545	$0.55194	$0.35049	$0.02532	$0.107		$0.00047
TOU Business	EBTOUT1		1.094	GELL	$1.525	$0.41395	$0.30663	$0.12364	$0.121		$0.01110
	EBTOUT2		1.094	GELL	$1.525	$0.41395	$0.30663	$0.12364	$0.218		$0.01330
	EBTOUT3		1.094	GELL	$1.525	$0.41395	$0.30663	$0.12364	$0.297		$0.01668
	WBTOUT1		1.184	GWLL	$2.295	$1.13411	$1.10426	$0.35443	$0.121		$0.01110
	WBTOUT2		1.184	GWLL	$2.295	$1.13411	$1.10426	$0.35443	$0.218		$0.01330
	WBTOUT3		1.184	GWLL	$2.295	$1.13411	$1.10426	$0.35443	$0.297		$0.01668
	MIBTOU		1.060	GMLL	$1.545	$0.41395	$0.40306	$0.04885	$0.107		$0.00047

2014-15 Rates TARIFFS APPLYING TO STANDARD ASSET CUSTOMERS – SMALL (<100 MWh per annum) CONTROLLED LOAD GST Exclusive										
Tariff Description	Network Tariff Code	Threshold Above Which Demand Charge Applies	Default Distribution Loss Factor		Distribution Use Of System (DUOS)			Transmission Use Of System (TUOS)		
					Fixed Charge (NDFC)	Actual Demand Charge (NDADC)	Volume Charge (NDVC)	Fixed Charge (NTFC)	Capacity Charge (NTCC)	Volume Charge (NTVC)
		kilowatts	Value	Code	dollars per day	dollars per kilowatt per month	dollars per kilowatt hour	dollars per day	dollars per kilowatt per month	dollars per kilowatt hour
Volume Night Controlled	EVNT1		1.094	GELL	$0.117		$0.00360			$0.01110
	EVNT2		1.094	GELL	$0.117		$0.00360			$0.01330
	EVNT3		1.094	GELL	$0.117		$0.00360			$0.01668
	WVNT1		1.184	GWLL	$0.138		$0.01139			$0.01110
	WVNT2		1.184	GWLL	$0.138		$0.01139			$0.01330
	WVNT3		1.184	GWLL	$0.138		$0.01139			$0.01668
	MIVN		1.060	GMLL	$0.148		$0.00335			$0.00047
Volume Controlled	EVCT1		1.094	GELL	$0.117		$0.03262			$0.01110
	EVCT2		1.094	GELL	$0.117		$0.03262			$0.01330
	EVCT3		1.094	GELL	$0.117		$0.03262			$0.01668
	WVCT1		1.184	GWLL	$0.138		$0.09154			$0.01110
	WVCT2		1.184	GWLL	$0.138		$0.09154			$0.01330
	WVCT3		1.184	GWLL	$0.138		$0.09154			$0.01668
	MIVC		1.060	GMLL	$0.148		$0.01253			$0.00047

2014-15 Rates TARIFFS APPLYING TO STANDARD ASSET CUSTOMERS – UNMETERED GST Exclusive										
Tariff Description	Network Tariff Code	Threshold Above Which Demand Charge Applies	Default Distribution Loss Factor		Distribution Use Of System (DUOS)			Transmission Use Of System (TUOS)		
					Fixed Charge (NDFC)	Actual Demand Charge (NDADC)	Volume Charge (NDVC)	Fixed Charge (NTFC)	Capacity Charge (NTCC)	Volume Charge (NTVC)
		kilowatts	Value	Code	dollars per day	dollars per kilowatt per month	dollars per kilowatt hour	dollars per day	dollars per kilowatt per month	dollars per kilowatt hour
Unmetered Supply	EVUT1		1.094	GELL	$0.006		$0.19544			$0.01110
	EVUT1MI		1.094	GELL	$0.006		$0.19544			$0.01110
	EVUT1MA		1.094	GELL	$0.006		$0.19544			$0.01110
	EVUT2		1.094	GELL	$0.006		$0.19544			$0.01330
	EVUT2MI		1.094	GELL	$0.006		$0.19544			$0.01330
	EVUT2MA		1.094	GELL	$0.006		$0.19544			$0.01330
	EVUT3		1.094	GELL	$0.006		$0.19544			$0.01668
	EVUT3MI		1.094	GELL	$0.006		$0.19544			$0.01668
	EVUT3MA		1.094	GELL	$0.006		$0.19544			$0.01668
	WVUT1		1.184	GWLL	$0.276		$0.16070			$0.01110
	WVUT1MI		1.184	GWLL	$0.276		$0.16070			$0.01110
	WVUT1MA		1.184	GWLL	$0.276		$0.16070			$0.01110
	WVUT2		1.184	GWLL	$0.276		$0.16070			$0.01330
	WVUT2MI		1.184	GWLL	$0.276		$0.16070			$0.01330
	WVUT2MA		1.184	GWLL	$0.276		$0.16070			$0.01330
	WVUT3		1.184	GWLL	$0.276		$0.16070			$0.01668
	WVUT3MI		1.184	GWLL	$0.276		$0.16070			$0.01668
	WVUT3MA		1.184	GWLL	$0.276		$0.16070			$0.01668
	MIVU		1.060	GMLL	$0.229		$0.03330			$0.00047
	MIVUMI		1.060	GMLL	$0.229		$0.03330			$0.00047
	MIVUMA		1.060	GMLL	$0.229		$0.03330			$0.00047

Explanatory notes

Inclining Block Tariff (IBT) tariffs

IBT Residential

The IBT Residential tariff will be the default primary network tariff applying to all residential SACs <100 MWh p.a.

It will incorporate the following charging parameters:

- a fixed charge ($/day)
- volume charges ($/kWh).

The volume charge will be charged according to three different blocks. The inclining blocks are triggered once a customer exceeds each nominated consumption threshold.

The following consumption blocks apply for IBT Residential tariffs:

Block	Daily kWh	Annual equivalent kWh
Block 1	0 – 2.74 kWh	0 – 1,000 kWh p.a.
Block 2	2.74 – 16.43 kWh	1,000 kWh p.a. – 6,000 kWh p.a.
Block 3	>16.43 kWh	>6,000 kWh p.a.

For network billing and operational purposes, the IBT is denominated and applied on a daily basis. The annual equivalent is provided for presentation purposes only.

IBT Business

The IBT Business tariff will be the default primary network tariff applying to all business SACs <100 MWh p.a.

It will incorporate the following charging parameters:

- a fixed charge ($/day)
- volume charges ($/kWh).

The volume charge will be charged according to three different blocks. The inclining blocks are triggered once a customer exceeds each nominated consumption threshold.

The following consumption blocks apply for IBT Business tariffs:

Block	Daily kWh	Annual equivalent kWh
Block 1	0 – 2.74 kWh	0 – 1,000 kWh p.a.
Block 2	2.74 – 54.76 kWh	1,000 kWh p.a. – 20,000 kWh p.a.
Block 3	>54.76 kWh	>20,000 kWh p.a.

For network billing and operational purposes, the IBT is denominated and applied on a daily basis. The annual equivalent is provided for presentation purposes only.

Seasonal Time-of-Use (TOU) tariffs

TOU Residential

These tariffs are voluntary for residential SACs <100 MWh p.a. from 1 July 2014. A customer (or their retailer) must request a tariff change to opt in to these tariffs. This is subject to metering considerations.

The TOU Residential tariffs will incorporate the following charging parameters:

- a fixed charge ($/day)
- volume charges ($/kWh).

The volume charge includes seasonal and time-of-day dimensions (Peak, Shoulder and Off-Peak time periods).

The following time periods apply for TOU Residential tariffs:

Peak	4:30pm to 9:00pm on Summer weekdays
Shoulder	3:00pm to 4:30pm and 9:00pm to 9:30pm on Summer weekdays, and 3:00pm to 9:30pm on Summer weekends
Off-Peak	All other times

Note: Summer is defined as the months of December, January and February.

TOU Business

These tariffs are voluntary for business SACs <100 MWh p.a. from 1 July 2014. A customer (or their retailer) must request a tariff change to opt in to these tariffs. This is subject to metering considerations.

The TOU Business tariffs will incorporate the following charging parameters:

- a fixed charge ($/day)
- volume charges ($/kWh).

The volume charge includes seasonal and time-of-day dimensions (Peak, Shoulder and Off-Peak time periods).

The following time periods apply for TOU Business tariffs:

Peak	11:30am to 5:30pm on Summer weekdays
Shoulder	10:00am to 11:30am and 5:30pm to 8:00pm on Summer weekdays
Off-Peak	All other times

Note: Summer is defined as the months of December, January and February.

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
- demonstration of how Ergon Energy meets the side constraints test under clause 6.18.6 of the NER
- the network tariff rates for 2014–15 and associated revenues and reconciliation.

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)[30]

Tariff class	2013–14	2014–15
Individually Calculated Customer (Pre 30 June 2010) – East	$44,270,700	$48,240,871
Individually Calculated Customer (Pre 30 June 2010) – West	$15,511,040	$18,041,871
Individually Calculated Customer (Pre 30 June 2010) – Mount Isa	$0	$0
Individually Calculated Customer (Post 30 June 2010) – East	$1,047,655	$1,289,757
Individually Calculated Customer (Post 30 June 2010) – West	$0	$0
Individually Calculated Customer (Post 30 June 2010) – Mount Isa	$0	$0
Connection Asset Customers (Pre 30 June 2010) – East	$82,366,881	$94,942,500
Connection Asset Customers (Pre 30 June 2010) – West	$11,441,634	$13,797,156
Connection Asset Customers (Pre 30 June 2010) – Mount Isa	$0	$0
Connection Asset Customers (Post 30 June 2010) – East	$4,895,336	$5,651,283
Connection Asset Customers (Post 30 June 2010) – West	$866,628	$1,005,700
Connection Asset Customers (Post 30 June 2010) – Mount Isa	$0	$0
Embedded Generation (Pre 30 June 2010) – East	$3,580,389	$4,071,633
Embedded Generation (Pre 30 June 2010) – West	$309,940	$360,741
Embedded Generation (Pre 30 June 2010) – Mount Isa	$0	$0
Embedded Generation (Post 30 June 2010) – East	$16,494	$19,810
Embedded Generation (Post 30 June 2010) – West	$0	$0
Embedded Generation (Post 30 June 2010) – Mount Isa	$0	$0
Standard Asset Customer – Large (>100 MWh p.a.) – East	$310,116,943	$354,170,263
Standard Asset Customer – Large (>100 MWh p.a.) – West	$81,279,897	$90,257,050
Standard Asset Customer – Large (>100 MWh p.a.) – Mount Isa	$4,990,591	$5,490,010
Standard Asset Customer – Small (<100 MWh p.a.) – East	$790,684,818	$914,514,252
Standard Asset Customer – Small (<100 MWh p.a.) – West	$221,097,418	$252,077,832
Standard Asset Customer – Small (<100 MWh p.a.) – Mount Isa	$13,163,973	$14,799,536
Standard Asset Customer – Unmetered – East	$19,033,098	$16,936,247
Standard Asset Customer – Unmetered – West	$2,783,367	$2,250,645
Standard Asset Customer – Unmetered – Mount Isa	$319,229	$351,957

[30] While Ergon Energy has made changes within our SAC <100 MWh p.a., SAC >100 MWh p.a. and ICC tariff classes, we still expect to recover the same amount of revenue from each tariff class under the new network tariff structures as we would have if the 2013–14 structures had remained in place.

Appendix 4: Alternative Control Services tariffs

This appendix sets out the tariffs applicable to Alternative Control Services in 2014–15.

All prices in this appendix are GST Exclusive.

Fee Based Services

Table A4.1: Fee Based Services prices

Service	2014-15 GST Exclusive
Subdivision fees	$959.34
Project fees	$959.34
De-energisation during business hours – urban/short rural feeders	$102.24
De-energisation during business hours – long rural / isolated feeders	$592.66
Re-energisation during business hours – urban/short rural feeders	$81.30
Re-energisation during business hours – long rural / isolated feeders	$552.36
Re-test at customer's installation during business hours – urban/short rural feeders	$355.59
Re-test at customer's installation during business hours – long rural / isolated feeders	$711.19
Supply abolishment during business hours – urban/short rural feeders	$355.59
Supply abolishment during business hours – long rural / isolated feeders	$711.19
Temporary Builders Supply, not in permanent position – single phase metered – business hours – urban/short rural feeders	$592.66
Temporary Builders Supply, not in permanent position – single phase metered – business hours – long rural / isolated feeders	$948.25
Temporary Builders Supply not in permanent position – multi phase metered – business hours – urban/short rural feeders	$592.66
Temporary Builders Supply not in permanent position – multi phase metered – business hours – long rural / isolated feeders	$948.25
Restoration of supply required due to customer action, during business hours – urban/short rural feeders	$355.59
Restoration of supply required due to customer action, during business hours – long rural / isolated feeders	$711.19
Wasted truck visit – one person crew – urban/short rural feeders	$56.00
Wasted truck visit – one person crew – long rural / isolated feeders	$224.01
Wasted truck visit – two person crew – urban/short rural feeders	$117.60
Wasted truck visit – two person crew – long rural / isolated feeders	$470.38

Quoted Services

In relation to each Quoted Service, it is important to note that the prices set out are examples of potential prices for 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.

Table A4.2: Quoted Services prices

Service	2014-15 GST Exclusive
Removal / relocation of Ergon Energy assets at customer request	$31,759.55
Move point of attachment at customer's request	$711.19
Tiger tails	$369.56
Metering Data Provider services	$162.39
Metering Data Provider services above minimum requirements	$440.53
Meter test	$474.13
Change tariff	$246.37
Change time switch	$123.19
Removal of meter	$237.06
Removal of load control device	$237.06
Special meter read	$59.36
Reprogram card meters	$369.56
Exchange meter	$355.59
Move meter	$355.59
Provision of connection services above minimum requirements	$780.58
Overhead service upgrade	$592.66
Underground service upgrade	$4,313.94
Provision, installation and maintenance of meters beyond minimum requirements at customer request	$761.94
Prepayment meters at customer request	$1,101.28
Temporary de-energisation and re-energisation	$355.59
De-energisation after hours	$254.62
Re-energisation after hours	$202.47
Attend loss of supply – not DNSP fault (after hours)	$460.16
Emergency Recoverable Works	$1,182.22
Subdivision fees	$1,649.86
Project fees	$634.56
High load escort – lifting of lines	$7,883.87
Rectification of illegal connections	$615.93
Conversion of aerial bundled cables	$731.92
Provision of service crew / additional crew	$307.96
Large Customer Connection – example 1	$186,799.32
Large Customer Connection – example 2	$10,837,609.77
Large Customer Connection – example 3	$11,814,743.65

ACS – Street Lighting Services

Table A4.3: ACS – Street Lighting Services prices

Street lighting charges	2014-15 Fixed charge ($/day/light) GST Exclusive
East – Major	$0.97
East – Minor	$0.58
West – Major	$0.97
West – Minor	$0.58
Mount Isa – Major	$0.97
Mount Isa – Minor	$0.58

Appendix 5: Alternative Control Services pricing models

These confidential models provide quantitative information to demonstrate the calculation of Fee Based and Quoted Services.

Appendix 6: Alternative Control Services reporting

This appendix sets out the volume and revenue Ergon Energy is required to report to the AER on our Fee Based Services, Quoted Services and ACS – Street Lighting Services, in accordance with the requirements set out in the AER's Final Distribution Determination.

Table A6.1: Fee Based Services – volumes and revenues for 2012–13

Service	Volume	Revenue ($'000)
Subdivision fees	8	$1.67
Project fees	6	$5.12
De-energisation during business hours	21,203	$5.40
Re-energisation during business hours	19,749	$142.53
Re-test at customer's installation during business hours	27	$7.01
Supply abolishment during business hours	693	$200.56
Temporary Builders Supply, not in permanent position – single phase metered – business hours	586	$196.93
Temporary Builders Supply not in permanent position – multi phase metered – business hours	4	$1.39
Restoration of supply required due to customer action, during business hours	10	$2.90
Wasted truck visit – one person crew	2,173	$106.44
Wasted truck visit – two person crew	242	$20.84

Table A6.2: Quoted Services – volumes and revenues for 2012–13

Service	Volume	Revenue ($'000)
Removal / relocation of Ergon Energy assets at customer request	449	$15,549.10
Move point of attachment during business hours - single/multi phase	1,109	$437.03
Tiger tails	274	$103.54
Provision of historical metering data	0	$0.00
Provision of metering data above minimum requirements	0	$0.00
Meter test	303	$4.61
Change tariff	47	$3.40
Change time switch	0	$0.00
Removal of a meter	372	$27.86
Removal of load control device	6	$0.33
Special meter read	761	$17.09
Reprogram card meters	0	$0.00
Exchange meter (Type 5-7)	111	$14.65
Move the meter (Type 5-7)	1,787	$239.04
Provision of connection services above minimum requirements	0	$0.00
Overhead service upgrade – no change to load	686	$290.61
Underground service upgrade	3	$1.18
Provision, installation and maintenance of meters above minimum requirements	192	$63.05
Prepayment meters at customer request	0	$0.00
Temporary de-energisation single visit during business hours – no dismantling	242	$113.21
De-energisation after hours	17	$5.87
Re-energisation after hours	721	$65.08
Restoration of supply required due to customer action – after hours	5	$1.94
Emergency Recoverable Works	300	$1,499.76
Subdivision fees	0	$0.00
Project fees	2,334	$1,263.06
High load escort	78	$154.54
Rectification of illegal connections	44	$129.88
Conversion of aerial bundled cables	1	$0.00
Provision of service during business/after hours requiring one/two person crew	53	$55.81
Large Customer Connections	14	$2,912.37

Table A6.3: ACS – Street Lighting Services – revenues for 2012–13

Street lighting charge	Revenue ($'000)
East – Major	$13,254.30
East – Minor	$13,290.70
West – Major	$862.56
West – Minor	$1,546.39
Mount Isa – Major	$805.50
Mount Isa – Minor	$643.67

In our 2013–14 Pricing Proposal, Ergon Energy indicated that billing associated with 2010–11 ACS – Street Lighting Services in Mount Isa occurred in 2012–13 and that this amount would be reported in the 2014–15 Pricing Proposal as part of the 2012–13 revenues.

Accordingly, the revenue reported above for Mount Isa – Major and Mount Isa – Minor includes revenue of $374,029 and $304,239 (respectively), which is associated with 2010–11. The total revenue for ACS – Street Lighting Services is consistent with the amount reported in the 2012–13 Annual Performance RIN.

Appendix 7: Proposed plan to clear DUOS under-recoveries

As discussed in Section 6.5.2 of this Pricing Proposal, Ergon Energy has exceeded the 5 per cent tolerance limit that applies to DUOS under/over recoveries. This appendix discusses how Ergon Energy proposes to clear the balance of our DUOS unders and overs account in accordance with section 4.4.2 of the AER's Final Distribution Determination.

It is important to note that the network tariffs set out in this Pricing Proposal have been calculated on the basis of this proposed plan. Should the AER make a determination that changes are required to any of the figures set out below, this Pricing Proposal will need to be revised to give effect to the AER's amendments.

Framework to clear Ergon Energy's DUOS under-recoveries

In our 2012–13 Pricing Proposal, Ergon Energy proposed that a longer term plan and framework be introduced from the 2012–13 regulatory year to clear any actual DUOS under/over recoveries associated with the 2010–15 regulatory period. This was in response to the 5 per cent tolerance limit being exceeded for the 2010–11 regulatory year and our forecast that the same would occur in the 2011–12 regulatory year.

To ensure customers do not experience unacceptably high annual price changes, Ergon Energy proposed a DUOS under-recovery plan which:

- progressively clears the balance of Ergon Energy's DUOS unders and overs account over the remaining years of the regulatory control period
- clears any residual balance left in the DUOS unders and overs account at the end of the regulatory control period, by making a carry forward adjustment into the next regulatory control period in the PTRM.

DUOS under-recoveries would be cleared in a manner which strikes a balance between minimising annual price changes to customers over the remaining years of the regulatory control period, while recovering a reasonable portion of our revenue allowances such that there is not an unreasonable carry-over amount into next regulatory control period.

Ergon Energy also proposed that revenue deductions arising from the Queensland Government direction on the ENCAP Review be incorporated into this plan, and used as a mechanism to smooth out increases in Ergon Energy's revenue caps. That is, Ergon Energy could use our discretion to decide the profile of how the $99.18 million would be passed through over the remaining years of the regulatory control period. Ergon Energy cleared all remaining balances of the ENCAP revenue in setting prices in 2013–14.

Ergon Energy's DUOS under-recoveries

Ergon Energy's DUOS unders and overs account (see Section 6.5.2) indicates that Ergon Energy has under-recovered $34.24 million in DUOS charges during the 2012–13 regulatory year (or $41.23 million once indexed for WACC). Combined with the opening DUOS unders and overs balance of $99.88 million associated with the 2010–11 and 2011–12 under-recoveries, this represents 8.06 per cent of Ergon Energy's MAR for 2014–15.

Consistent with the tolerance limit arrangements set out in section 4.4.2 of the Final Distribution Determination and the DUOS under-recovery plan detailed in our 2012–13 and 2013–14 Pricing Proposals (which were approved by the AER), Ergon Energy proposes to spread these DUOS under-recoveries over multiple regulatory years. In the network tariffs we set for 2014–15, Ergon Energy will clear the remaining balance of the 2010–11 under-recovery and most of the 2011–12 under-recovery. We will not clear any of the 2012–13 under-recovery in 2014–15.

The residual balance of $53.57 million[31] left in the DUOS unders and overs account as at 30 June 2015 will be cleared by making a carry forward adjustment in the PTRM in the next regulatory control period. Our submission to the AER's *Preliminary positions paper – Framework and Approach for Energex and Ergon Energy – Regulatory control period commencing 1 July 2015* [32] sets out our proposed approach to determining this adjustment and entering it in the PTRM. We will continue to work with the AER on this issue as part of the regulatory determination process.

Approval process

In our 2012–13 Pricing Proposal, Ergon Energy suggested that actual adjustments in our DUOS under-recovery plan should be approved annually by the AER as part of the Pricing Proposal. This approach allows Ergon Energy and the AER to reassess the most appropriate means to recover the balance of any remaining DUOS under/over recoveries once the magnitude and impact of actual future year revenue adjustments is known.

This means for the purpose of this Pricing Proposal, Ergon Energy only wishes to seek AER approval of the proposed 2014–15 revenue adjustments required to clear the remaining balance of the 2010–11 under-recovery and 2011–12 under-recovery amount proposed to be cleared in 2014–15. The proposed adjustments are highlighted in Tables A7.1 and A7.2 below.

The carry forward adjustment required to clear the residual balance as at 30 June 2015 will be approved by the AER in its 2015–20 Distribution Determination for Ergon Energy.

It should be noted that any DUOS under or over recovery for 2013–14 will be assessed and approved as part of the 2015–16 Pricing Proposal, in accordance with the requirements of the 2015–20 Distribution Determination.

Proposed revenue adjustments

Table A7.1 sets out how Ergon Energy currently proposes to spread the recovery of our actual DUOS under-recoveries. It also illustrates the impact on Ergon Energy's expected revenues with and without the proposed smoothing of DUOS under-recoveries.

Table A7.2 sets out the estimated opening and closing balances of the DUOS unders and overs account for 2014–15 under Ergon Energy's proposed DUOS under-recovery plan. It also shows the estimated carry forward adjustment into the next regulatory control period.

[31] Associated with the remaining balance of the 2011–12 under-recovery and the entire 2012–13 under-recovery
[32] Refer to page 22, available at http://www.aer.gov.au/node/20186.

Table A7.1: Proposed revenue adjustments and impact of smoothing DUOS under-recoveries ($M, nominal)

		Actual							Proposed
		2010–11	2011–12		2012–13		2013–14		2014–15
No smoothing of DUOS under-recoveries	MAR	$1,076.71	$1,235.32		$1,402.89		$1,602.60		$1,750.77
	+/- DUOS unders/overs (unsmoothed)	$6.00	$0.30		$78.90		$59.59		$41.23
	Less revenue adjustment for Qld Govt Direction on Gamma & ENCAP	n/a	($40.86)	*	($57.03)	**	($42.15)	**	$0.00
	'Revenue Cap' to be used for pricing	**$1,082.71**	**$1,194.76**		**$1,424.76**		**$1,620.04**		**$1,792.00**
	% change in Revenue Cap		**10.35%**		**19.25%**		**13.71%**		**10.61%**
With proposed smoothing of DUOS under-recoveries	MAR	$1,076.71	$1,235.32		$1,402.89		$1,602.60		$1,750.77
	+/- DUOS unders/overs (smoothed)	$6.00	$0.30		$21.04		$32.05		$87.54
	Less revenue adjustment for Qld Govt Direction on Gamma & ENCAP	n/a	($40.86)	*	($57.03)	**	($42.15)	**	$0.00
	'Revenue Cap' to be used for pricing	**$1,082.71**	**$1,194.76**		**$1,366.90**		**$1,592.50**		**$1,838.31**
	% change in Revenue Cap		**10.35%**		**14.41%**		**16.50%**		**15.44%**

* Relates to Queensland Government direction on Gamma.

** Relates to Queensland Government direction on ENCAP.

Table A7.2: Proposed plan to clear the DUOS unders and overs account and projected opening and closing balances ($M, nominal)

	Actual					Proposed	Forecast	
	2010–11	2011–12	2012–13	2013–14		2014–15	Next Period	
Proposed DUOS under/over adjustment for year t (% of MAR)			1.50%	2.00%		5.00%		
Opening balance on DUOS unders and overs account in year t		$0.00	$0.00	($63.48)		($99.88)	($57.58)	*
Plus other DUOS under/over adjustments approved by the regulator		$0.00	$0.00	($0.01)	**	$0.00		
Plus DUOS under/over recovery from regulatory year t-2	($6.00)	($0.30)	($78.90)	($59.59)		($41.23)		
Less DUOS unders/overs to be passed through in year t	$6.00	$0.30	$21.04	$32.05		$87.54		
Closing balance on DUOS unders and overs account in year t	$0.00	$0.00	($57.86)	($91.03)		($53.57)		

* Represents Ergon Energy's current forecast of the carry-forward adjustment required in the PTRM to zero the balance of the DUOS unders and overs account at the start of the next regulatory control period.

** Relates to Ergon Energy's proposed adjustment to the opening balance relating to an immaterial misstatement in 2012-13.

Appendix 8: Avoidable and stand alone costs for Standard Control Services

This model demonstrates how Ergon Energy meets the tests for avoidable and stand alone costs under clause 6.18.5 of the NER.

Glossary

Abbreviations

ABS	Australian Bureau of Statistics
ACS	Alternative Control Services
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AR	Allowed Revenue
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
EG	Embedded Generator
ENCAP Review	Queensland Electricity Network Capital Program Review 2011
Ergon Energy	Ergon Energy Corporation Limited
GWh	Gigawatt hour
IBT	Inclining Block Tariff
ICC	Individually Calculated Customer
IDC	Interdepartmental Committee on Electricity Sector Reform
kV	Kilovolt
kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt hour
Law	National Electricity Law
LOB	Line of Business
LRMC	Long Run Marginal Cost
MAR	Maximum Allowable Revenue
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
QCA	Queensland Competition Authority
RIN	Regulatory Information Notice
ROA	Return on assets
SAC	Standard Asset Customer
SCS	Standard Control Services
STPIS	Service Target Performance Incentive Scheme
TNSP	Transmission Network Service Provider
TOU	Time-of-Use
Tribunal	Australian Competition Tribunal
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital

Definitions

ACS – Street Lighting Services	A type of Alternative Control Service. Relates to the installation, operation and maintenance of street lighting assets owned by Ergon Energy. Ergon Energy recovers our costs in providing this service through a daily street lighting charge which we bill to retailers.
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 and ACS – Street Lighting Services.
Annual revenue adjustment	Annual adjustments made to Ergon Energy's allowed revenue for matters such as out-turn inflation, 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 allowed to be recovered from various customer groups through Ergon Energy's network tariffs after annual revenue adjustments. Also referred to as the 'Revenue Cap'.
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).
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 Capital Contribution 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.
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.
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 ARR 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 "Network Tariff 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 those customers with micro generation facilities 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).
Fee Based Service	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 main network, connection and metering services and is levied as a separate charge. Fee Based Services have a fixed fee 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.
Final Distribution Determination	The AER's Final Distribution Determination sets the revenue and pricing control regime that Ergon Energy must comply with for the current regulatory control period.

Fixed charge	A type of charge (charging parameter) included in Ergon Energy network tariffs which reflects the costs associated with connection assets (entry and exit services) and network user management services. For those customers with consumption less than 100 MWh per annum (SACs <100 MWh p.a.), the fixed charge also recovers a portion of the shared network costs. The charge 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.
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.
kW	1,000 Watts which is a measure of the real component of power being consumed by the consumer's load.
Large customer	Are Individually Calculated Customers (ICCs), Connection Asset Customers (CACs) or Embedded Generators (EGs).
Large 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 large customer (i.e. not included in the network tariff).
Large Customer Connection service	Is a type of Quoted Service which relates to the design and construction of connection assets for large customers.
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.
Maximum Allowable Revenue (MAR)	The maximum revenue which can be recovered through tariffs for the regulatory year prior to adjustments for any under or over recovery in DUOS charges.

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 "Network Tariff 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.
Quoted Service	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) are 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 2010–11 to 2014–15.
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).
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.
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 a similar service connection and usage profile as other SACs without such facilities.
Standard Control Service	A distribution service provided by Ergon Energy that the AER has classified as a Standard Control Service under the NER. Includes core network, connection and metering services associated with the access and supply of electricity to customers. Ergon Energy recovers our costs in providing Standard Control Services through the DUOS component of network tariffs which are billed to retailers.
Street lights – Major	Standard major street lights are 100, 150, 250 and 400 watt High Pressure Sodium vapour lights and include any other non-standard or obsolete street lights that would be replaced with any of the above lights.
Street lights – Minor	Standard minor street lights are 50, 80 and 125 watt Mercury Vapour, 70 watt High Pressure Sodium vapour lights, and compact fluorescent lights of similar luminescence and include any other non-standard or obsolete street lights that would be replaced with any of the above lights.
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. The threshold adjustment is effective for 2014–15 SAC >100 MWh p.a. network tariffs. The adjustment was introduced to avoid over-recovery of revenue arising from increasing the fixed charge to offset the removal of the minimum monthly demand charge in 2014–15.
Time-of-Use (TOU)	A type of network tariff where the price per kWh varies according to when the consumption occurs. The TOU tariff applies 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.
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 "Network Tariff Guide for Standard Control Services".

Contact information

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