Annual Pricing Proposal

Distribution services for 1 July 2018 to 30 June 2019

Version control

Version	Date	Summary of changes
1.0	31 March 2018	Initial Pricing Proposal submitted to the AER for approval.
2.0	20 April 2018	Revised Pricing Proposal with minor updates

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The following attachments referenced throughout this document accompany our Pricing Proposal:

- Attachment 1: Ergon Energy 2018-19 Network Tariff Tables
- Attachment 2: Ergon Energy Indicative Pricing Schedule
- Attachment 3: Differences between indicative 2018-19 prices and proposed 2018-19 prices.
- A (confidential) Tariff Approval Model has also been provided to the AER.

1 Introduction

1.1 Background

On 30 June 2016, Ergon Energy Corporation Limited (Ergon Energy) became a subsidiary of Energy Queensland Limited which is the holding company for both Energex and Ergon Energy. Ergon Energy is the Distribution Network Service Provider (DNSP) that builds, owns, operates and maintains the electricity distribution network in regional Queensland. We provide distribution services to around 730,000 customers. Our service area covers around 97 per cent of Queensland and has approximately 160,000 kilometres of power lines and one million power poles. Around 70 per cent of our network's power lines are radial and service mostly rural areas with very low levels of customers per line kilometre.

Our key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for our customers, manages risk and builds a sustainable future.

1.2 Purpose

This document is Ergon Energy's Annual Pricing Proposal for 2018-19 (Pricing Proposal). In accordance with clause 6.18.2(a)(2) of the *National Electricity Rules* (NER),[1] it is submitted for approval to the Australian Energy Regulator (AER) at least three months before the commencement of the regulatory year (that is, 31 March 2018).

The AER approves prices for services it classifies as Direct Control Services. This Pricing Proposal (and the attachments forming part of this Pricing Proposal) has been prepared to assist the AER in approving these prices. It sets out how our proposed tariffs and/or prices for Direct Control Services in 2018-19 meet the requirements of the NER.

1.3 Classification of services

The AER determines how Ergon Energy's distribution services are classified and in turn the nature of economic regulation. This is important as it determines how prices will be set and how revenue is recovered from customers.

Services classified as Direct Control Services are comprised of Standard Control Services and Alternative Control Services.

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

Alternative Control Services are comprised of:

- Fee based services – one-off distribution services that we undertake at the request of an identifiable customer, retailer or appropriate third party which are levied as a separate charge, in addition to our Standard Control Services. These services are priced on a 'fixed fee' basis as

[1] National Electricity Rules, Version 106.

the costs of providing the service (and therefore price) can be assessed in advance of the service being requested.

- Examples of fee based services include temporary connections, de-energisations, re-energisations and supply abolishment.
- 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 requestor's needs (e.g. design and construction of connection assets for major customers, real estate development connections and special meter reads etc.).
- Default Metering Services – relate to:
  - Type 5 and 6 meter installation and provision (before 1 July 2015)
  - Type 5 and 6 meter installation and provision (on or after 1 July 2015 up until 30 November 2017)[2], where the replacement meter was initiated by Ergon Energy as a DNSP
  - Type 5 and 6 metering maintenance, reading and data services.

We recover the costs of providing Default Metering Services through daily capital and non-capital charges based on the number and type of meters we provide the customer. These charges are billed to retailers.

It should be noted that, as a result of Power of Choice taking effect on 1 December 2017, the installation and delivery of most metering services have become the responsibility of third party service providers.[3] Ergon Energy remains responsible for the maintenance of its existing fleet of Type 6 meters.

- Public Lighting Services – relate to the provision, construction and maintenance of public lighting assets owned by Ergon Energy, and emerging public lighting technology. We recover the costs of providing Public Lighting Services through a daily public lighting charge billed to retailers. We may also charge a one-off exit fee, when a customer requests the replacement of an existing public light for a light emitting diode (LED) luminaire before the end of its useful life.[4]

The tariff schedules for our Standard Control Services and Alternative Control Services is set out in Attachment 1.

1.4 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 we can earn, and the prices that we can charge for the provision of network services.

1.4.1 Distribution Determination

In October 2015, the AER made its Final Decision on Ergon Energy's Distribution Determination for the 2015-20 regulatory control period (Distribution Determination). The Distribution Determination sets the revenue and pricing control regime that we must comply with for the regulated distribution services provided over the current regulatory control period. The revenue approved in the Distribution Determination forms the basis of Ergon Energy's prices provided in Attachment 1.

[2] The Power of Choice changes only apply to supply networks that are connected to the national grid, and subject to Chapter 7 of the NER. Ergon Energy will remain responsible for metering in our Mount Isa-Cloncurry and Isolated supply networks.

[3] Ibid.

[4] Outside of our LED transition program.

The Distribution Determination also details how we must report on the recovery of jurisdictional scheme amounts which comprise:

- feed-in tariff (FiT) payments made under the Queensland Government's Solar Bonus Scheme
- the energy industry levy payable to the Australian Energy Market Commission (AEMC) for the work it performs under the National Energy Retail Law.

It should be noted that, on 31 May 2017, we received a direction from the Queensland Government not to pass on any jurisdictional scheme amounts to customers through our network charges. The Queensland Government will instead subsidise the cost of the Solar Bonus Scheme until at least 2020. Consequently, since 1 July 2017, the jurisdictional scheme rates in Ergon Energy's network tariffs have been set to zero.

1.4.2 Tariff Structure Statement

In November 2014, amendments to the NER fundamentally changed the framework in which tariffs for Direct Control Services are developed. Included in these arrangements were new obligations for DNSPs, including Ergon Energy, to develop prices that better reflect the costs of providing services to customers so that they can make informed decisions about how they use electricity.

As part of this new framework, we developed and submitted to the AER for approval a Tariff Structure Statement (TSS) for the 2017 to 2020 period.[5] The AER approved Ergon Energy's TSS on 28 February 2017.[6]

The TSS sets out our proposed tariff classes, tariffs and tariff structures that will apply over the regulatory control period, and demonstrates compliance with the new pricing principles. The TSS interfaces with Ergon Energy's Pricing Proposal, and each Pricing Proposal must be consistent with the approved TSS. This Pricing Proposal is the second Pricing Proposal developed in accordance with the 2017-20 TSS.

As much of the content in our TSS around adherence to the pricing principles and tariff development is directly relevant to our 2018-19 prices, several sections of this Pricing Proposal therefore refer to the TSS for further information.

1.4.3 Pricing objective and principles

In accordance with clause 6.18.5(a) of the NER, our objective is to ensure that the tariffs charged for 2018-19 in respect of the provision of Direct Control Services reflect Ergon Energy's cost of providing these services. This is achieved by setting the level (or price) of tariffs in a manner that is consistent with the pricing principles outlined in clauses 6.18.5(e) to (j) of the NER. For example, the NER requires Ergon Energy to demonstrate that:

- each tariff is set based on the Long Run Marginal Cost (LRMC) of providing the network service to the customers assigned to that tariff (clause 6.18.5(f))
- tariffs are set in a manner that minimises distortions to the price signal resulting from complying with the LRMC pricing principle and the efficient usage decisions of consumers (clause 6.18.5(g)(3))
- the revenue expected to be recovered from each tariff reflects Ergon Energy's total efficient costs (clause 6.18.5(g)(1))

[5] Under the transitional arrangements, the initial TSS covers only the last three years of the 2015-20 regulatory control period (i.e. 1 July 2017 to 30 June 2020).

[6] AER's Final Decision on Ergon Energy's 2017-20 TSS is available on the AER's website: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs/ergon-energy-tariff-structure-statement-2017.

- we have considered the impact on customers of changes to tariffs between regulatory years, and we have adjusted prices to the extent necessary to meet the customer impact principles and ensure a smooth transition to cost reflectivity (clause 6.18.5(h))
- tariff structures are set in a manner that can be understood by customers (clause 6.18.5(i)).
- tariffs comply with the NER and all applicable regulatory instruments (clause 6.18.5(j)).

The expected revenue recovered from our tariffs must also:

- for each tariff class, lie between the stand alone costs of serving those customers and the avoidable costs of not serving those customers (clause 6.18.5(e)(1) and (2))
- for each tariff, reflect our efficient costs of serving customers assigned to that tariff (clause 6.18.5(g)(1))
- enable us to recover the expected total annual revenue as set by the AER in the Distribution Determination (clause 6.18.5(g)(2)).

More detailed information about our application of, and compliance with, the distribution pricing principles is set out in this Pricing Proposal and our TSS.

1.4.4 Queensland Government cap on fee based and quoted services

The Queensland Government has historically set maximum price caps to apply to a subset of Ergon Energy's Alternative Control 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.

It is important to note that the prices contained in this Pricing Proposal have been derived under the tariff-setting requirements. These services, if subject to the maximum price caps in Schedule 8, may be higher than those charged to customers.

1.5 Summary of changes

We are proposing a number of changes to our network tariffs for Standard Control Services in 2018-19. Key changes are summarised in Table 1-1 below.

Table 1-1: Network tariff changes

Network user group	Tariff changes
SAC Residential	To inform the development of our forthcoming 2020-25 TSS, we propose to introduce a new cost reflective network tariff, Lifestyle tariff, that is to be offered to retail customer subjects to the limitations of the threshold tariff provisions set out in clause 6.18.1C of the NER. This innovative tariff is a departure from conventional demand-based tariffs currently offered in the NEM. This small scale tariff offering will enable us and retailers to market test the tariff during the current 2017-20 TSS period. The rates applicable for 2018-19 for the tariff are provided in Attachment 1.

Further details on the 2018-19 changes are set out in Section 5.3.

1.6 Structure of this document

This Pricing Proposal should be read in conjunction with our approved TSS. Our TSS provides detailed information on our network tariff structures and charges for the 2017 to 2020 period, and how we comply with the NER and pricing principles.

The structure of this Pricing Proposal is set out in Table 1-2 below.

Table 1-2: Pricing Proposal structure

Chapter	Title	Overview
1	Introduction	Provides an overview of the 2018-19 Pricing Proposal and the context in which we develop prices, including the relationship with the regulatory framework and our TSS.
2	Tariff classes and tariffs for Standard Control Services	Sets out for 2018-19 the tariff classes, tariffs, tariff structures, and tariff assignment policies for our Standard Control Services.
3	Tariff levels for Standard Control Services	Details how we have set the prices for our Standard Control Services for 2018-19 in accordance with the requirements of the NER and the AER's Distribution Determination.
4	Alternative Control Services	Outlines for 2018-19 the tariff classes, tariffs, tariff structures, control mechanisms and tariff assignment policy for Alternative Control Services in accordance with the requirements of the NER and the AER's Distribution Determination.
5	Other compliance	Demonstrates our compliance with other regulatory requirements which have not been covered in previous chapters
	Appendices	Provides additional supporting information, including: ○ Proposed Standard Control Services tariffs and tariff structures for 2018-19 ○ Compliance matrix ○ Glossary ○ Confidentiality template

We have also provided a number of models and supporting attachments to the AER as part of this Pricing Proposal. Where possible, these documents will be made publicly available. The documents subject to confidentiality requirements are listed in Appendix 4 of this Pricing Proposal.

1.7 Alignment of pricing proposals

In 2017-18, Ergon Energy and Energex, as subsidiaries of Energy Queensland Limited, commenced the process of aligning our pricing proposals by adopting similar structures. In 2018-19, the alignment between our pricing proposals has been further progressed with the adoption of similar contents wherever possible. This initiative is part of the wider endeavour to align the businesses' activities in order to achieve greater efficiencies and consistency across Queensland.

1.8 Supporting network pricing documents

In addition to this Pricing Proposal, we have developed and published on our website a number of related network pricing documents to assist network users, retailers and interested parties understand the development and application of tariffs and connection charges.[7] These documents outlined in Figure 1.1 below.

[7] Link to the pricing page on Ergon Energy's website: www.ergon.com.au/network/network-management/network-pricing.

Figure 1.1: Supporting network pricing documentation

Document	Description
Tariff Structure Statement	• Sets out the proposed tariff structures for the 2017 to 2020 period • Details how the proposed tariff structures comply with the pricing principles • Describes the tariff-setting process for Standard and Alternative Control Services • Provides details on the assignment of customers to tariff classes and tariffs • Approved by the AER in February 2017, following stakeholder consultation
Pricing Proposal	• Provides how Ergon Energy's tariff classes, tariffs and tariff structures for our Standard Control Services and Alternative Control Services in compliance with the requirements set out in Chapter 6 of the NER, the AER's Distribution Determination and our TSS. • Provides indicative prices for 2019-20 • Submitted to the AER annually.
2018-19 Network Tariff Tables	• Provides Ergon Energy's prices for our Standard Control Services and Alternative Control Services developed in accordance with the requirements set out in Chapter 6 of the NER, the AER's Distribution Determination and our TSS. • Submitted to the AER annually as part of the Pricing Proposal. • Referred as to Attachment 1 in this Pricing Proposal.
Information Guide for Standard Control Services Pricing	• Sets out the basis upon which Ergon Energy's revenue cap for Standard Control Services is recovered from various customer groups through network tariffs. • Provides a description of the network tariffs • Published annually.
User Guides	• Provide an introduction to the current network tariffs for each customer group • Published annually, and updated as required
Network Tariff Guide	• An operational document for customers, retailers and consultants, setting out the Network Tariff Codes and application rules and rates for each Network Tariff Code • Applies to network users connected to Ergon Energy's regulated distribution network • Published annually, and updated as required
Price List for Alternative Control Services	• Sets out Ergon Energy's Alternative Control Services and the prices that apply for fee based services, Default Metering Services and Public Lighting Services • Published annually, and updated as required
Connection Policy	• Sets out when a connection charge may be payable by retail customers or real estate developers and the aspects of the connection service for which a charge may be applied • Details how Ergon Energy calculates the capital contribution to be paid • Approved by the AER in 2015 as part of the Distribution Determination

2 Tariff classes and tariffs for Standard Control Services

Rule requirement

Clause 6.18.2 Pricing proposals

(b) A pricing proposal must:

(2) set out the proposed tariffs for each tariff class that is specified in the Distribution Network Service Provider's tariff structure statement for the relevant regulatory control period.

(3) set out for each proposed tariff, the charging parameters and the elements of service to which each charging parameter relates.

Clause 6.18.3 Tariff classes

(b) Each customer for direct control services must be a member of 1 or more tariff classes

(c) Separate tariff classes must be constituted for retail customers to whom standard control services are supplied .

(d) A tariff class must be constituted with regard to:

(1) the need to group retail customers together on an economically efficient basis; and

(2) the need to avoid unnecessary transaction costs.

This chapter sets out Ergon Energy's tariff classes, tariffs, tariff structures and tariff assignment policies for Standard Control Services in accordance with the NER requirements and our TSS.

2.1 Tariff classes

Under chapter 10 of the NER, tariff classes are defined as 'a class of customers for one or more direct control services who are subject to a particular tariff or particular tariffs'.

Clauses 6.18.3 (c) and (d) set out that separate tariff classes must be constituted for customers receiving Standard Control Services having regard to the need to group our customers together on an economically efficient basis, and the need to avoid unnecessary transactions costs. These requirements ensure a balance is struck between:

- setting tariff classes (and tariffs) that send efficient signals to customers about their use of the network – which, in principle, will vary according to each individual customer's voltage level, size, consumption pattern/profile and location/feeder within the network- and
- minimising the costs associated with developing, administering and implementing a large number of bespoke tariff classes (and tariffs).

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 customers with broadly similar characteristics, who impose similar costs on the network, are classed together so that they face similar tariff structures.

Consistent with our TSS, Ergon Energy will apply 18 tariff classes for Standard Control Services in 2018-19, as shown in Table 2-1 below.[8] Ergon Energy's selection of Standard Control Service tariff classes aligns with our cost allocation process for tariff-setting by differentiating between:

- customer groups
  - Individually Calculated Customers (ICCs)
  - Connection Asset Customers (CACs)
  - Standard Asset Customers (SACs):

[8] NER, clause 6.18.2(b)(2).

        - SAC Large
        - SAC Small
        - SAC Unmetered
    - Embedded Generators (EGs)
- locational zones
    - East Zone
    - West Zone
    - Mount Isa Zone.

For example, we have a tariff class for ICCs in the East Zone, West Zone and Mount Isa Zone.

Table 2-1: Ergon Energy's Standard Control Service tariff classes

Customer group	East Zone	West Zone	Mount Isa Zone
ICC	●	●	●
CAC	●	●	●
EG	●	●	●
SAC Large	●	●	●
SAC Small	●	●	●
SAC Unmetered	●	●	●

Consistent with clause 6.18.3(b) of the NER, all of our customers receiving Standard Control Services are a member of one or more tariff classes shown in Table 2.1.

2.2 Tariffs and tariff structures

Each tariff class consists of a number of individual tariffs. Each tariff comprises a combination of charges that we apply to customers (through their retailer) to recover network costs. In developing our network tariffs, we have ensured that they provide signals to network users about the efficient use of the network. Finally, in accordance with clause 6.18.5(i), our tariff structures have been developed so that they can be easily understood by customers.

Details of the rationale for our network tariffs, tariff structures and implementation approach for the 2017-20 period are outlined in our TSS.

Tariffs have three key defining characteristics:

- the charge (can also be called a ‘charging component’, ‘tariff component’ or ‘tariff element’)
- the parameters of the charge (specific characteristics that relate to the charge that influence how it is calculated)
- the rate applied to each charge.

Each tariff has at least one charge, but usually has more than one. The types of charges and charging parameters used for our Standard Control Services are shown in Table 2-2.

Each charge and charging parameter is selected and structured to provide signals to network users about the efficient use of the network. This is particularly the case for the newly introduced optional cost reflective LRMC-based tariffs. More detailed information on charges and charging parameters by tariff is available in our TSS.

Table 2-2: Types of charges and charging parameters for Standard Control Services for 2018-19

Charge	Charging parameter	Application to tariffs
Fixed charge	Represented as a rate ($) per day or rate ($) per day per device.	Applies to all tariffs except: ○ Residential STOUD ○ Business STOUD ○ CAC STOUD.
Usage (or volume) charge	Represented as a rate ($) per kWh. Different parameters apply to this charge for different tariffs. Within a tariff structure, usage charge rates can be flat or be applied to different blocks (based on consumption) or times (peak and off-peak).	Applies to all tariffs except EGs.
Demand charge	Represented as either a rate ($) per kW or a rate ($) per kVA. Different parameters apply to this charge for different tariffs. Within a tariff structure, demand charge rates can be: ○ applied year round or seasonally (with different peak and off-peak rates) ○ calculated based on: – a single period in the month – the maximum demand within a peak demand window – an average of demands within a demand window. Some tariff structures include a floor (the demand charge must include at least the rate times 'X' demand) or a threshold (the demand charge is only calculated for demands recorded above a particular level).	Applies to all tariffs except: ○ Residential IBT and Lifestyle Tariff ○ Business IBT ○ Residential STOUE ○ Business STOUE ○ Controlled load ○ Unmetered supplies ○ EGs.
Capacity charge	Represented as a rate ($) per kVA.	Applies to the following tariffs: ○ CAC any time demand tariffs ○ CAC STOUD ○ ICC site-specific tariffs.
Excess reactive power charge	Represented as a rate ($) per excess kVAr.	Applies to the following tariffs: ○ ICC site-specific tariffs. ○ CAC any time demand tariffs ○ CAC STOUD
Network access allowance	Represented as a rate ($) per month. Monthly charge based on the customer's nominated access band.	Applies to the following tariff: ○ Residential Lifestyle Tariff
Summer peak top-up charge	Represented as a rate ($) per kWh consumed above the customer's nominated band within a month during the summer peak window.	Applies to the following tariff: ○ Residential Lifestyle Tariff
Connection unit charge	Represented as a rate ($) per connection unit per day.	Applies to the following tariffs: ○ CAC any time demand tariffs ○ CAC STOUD.

Clause 6.18.2(b)(2) of the NER requires that we set out in our pricing proposal the proposed tariffs for each tariff class specified in our TSS. Accordingly, our network tariffs – including their charges and charging parameters – for Standard Control Services offered in 2018-19 are included in Appendix 1 of this Pricing Proposal and in Attachment 1.[9]

2.3 Tariff assignment policies

Rule requirement

Clause 6.18.1A Tariff structure statement

(a)(2) A *tariff structure statement* must include the policies and procedures the *Distribution Network Service Provider* will apply for assigning *retail customers* to tariffs or reassigning *retail customers* from one tariff to another (including any applicable restrictions).

Distribution Determination requirement

Attachment 14 - D.3 Procedures for assigning or reassigning retail customer to tariff classes

To meet the requirements of clause 6.18.1A(a)(2) of the NER and the general procedures set out in Attachment 14 of the Distribution Determination, we have developed detailed procedures for the assignment and reassignment of customers to Standard Control Services tariff classes and tariffs. Consistent with the NER requirements, these policies and procedures are contained in our TSS (refer to Appendix D of our TSS). We will comply with these procedures in 2018-19.

In addition, Attachment 14 of the Distribution Determination requires Ergon Energy's Pricing Proposal to set out a method of how we will review and assess the basis on which a customer is charged, where the charging parameters for a particular tariff result in a basis of charge that varies according to the customer's usage or load profile.[10] Our compliance with this requirement for Standard Control Service tariff classes is set out below and also in our TSS.

Review of the charging basis

We may review the charging basis where:

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

We annually review 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 to determine when it is appropriate for a customer to be reassigned to a different tariff class as a result of a material change in the customer's energy consumption or connection characteristics (refer to Appendix D of our TSS). These procedures, in conjunction with the classification of SAC Small customers as business or residential, also ensure the customer's underlying network tariff associated with a tariff class remains appropriate.

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9 It should be noted that we had foreshowed in our TSS our intention to introduce additional controlled load tariffs – Demand Controlled – from 2015-16. However, this inititative is dependent on the availability of load control products which remains, at this stage, relatively limited. As a result, the introduction of new load control tariffs has been postponed.

10 AER, Final Decision Ergon Energy Determination 2015-16 to 2019-20, Attachment 14 – Control mechanisms, October 2015, page 34.

In addition to this annual review process, customers and/or retailers can expressly request that we 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. Should we agree to the change in network tariff, this change can take effect during a regulatory year. Further information on network tariff reviews is contained in Appendix D of our TSS.

With respect to variations in the basis of charge within a network tariff, it should be noted that the structure and rates of each charge and charging parameter within a tariff (see Table 2-2) apply equally to each customer assigned to the network tariff, regardless of a customer's individual usage or load profile. However, the actual network charges applied to customers may vary.

For example, the actual network charges applied to SAC Small customers on an IBT will vary according to their level of usage. Similarly, for customers on Time-of-Use (TOU) tariffs, the network charges will vary according to when their usage (demand or energy, depending on the tariff) occurs. For our ICCs and CACs, the excess kVAr charge may apply to customers with a poor power factor.

Should a customer's usage or load profile vary, the customer can either manage their usage by responding to the price signals inherent in the charges and 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.

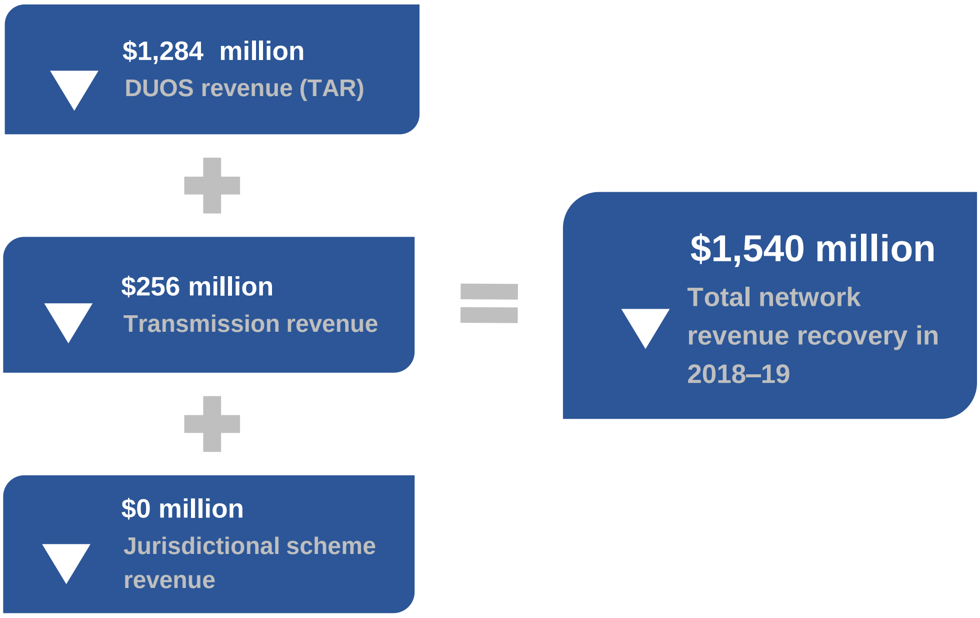
3 Tariff levels for Standard Control Services

This chapter sets out how we have developed our 2018-19 network prices for Standard Control Services in compliance with the regulatory requirements in Chapter 6 of the NER.

3.1 Total Revenue Requirement for 2018-19

In 2018-19, the total network revenue that we will need to recover from network users (via our tariffs) is approximately $1,540 million as shown in Figure 3.1. Detailed calculations are provided in Table 3-1.

Figure 3.1: Summary total network revenue for 2018-19



The amount to be recovered includes Ergon Energy's Total Annual Revenue (TAR), transmission costs[11] jurisdictional scheme amounts (set to nil until at least 2020).

The TAR, which reflects Ergon Energy's smoothed expected revenue plus other adjustments, will be approximately $1,284 million in 2018-19. This is 3.8 per cent below what we expected to recover from network users in 2017-18.

When calculating the smoothed expected revenue, we applied the revenue cap formulae set out by the AER in the Distribution Determination.

[11] Transmission costs are also known as Designated Pricing Proposal Costs (DPPC) or Transmission Use of System (TUoS).

3.2 Distribution Use of System (DUOS) charges

3.2.1 Control mechanism

Distribution Determination requirement

Attachment 14 – Ergon Energy must demonstrate compliance with the control mechanism for Standard Control Services in accordance with Figure 14.1 – including adjustments for DUOS under or over recovery in accordance with Appendix A of this attachment

Total Annual Revenue (TAR)

In the Distribution Determination, the AER decided the control mechanism to apply to our Standard Control Services is a revenue cap. The revenue cap for any given regulatory year is the TAR.

In accordance with the Distribution Determination, we applied the following formulae when calculating the TAR for a given regulatory year:

Figure 3.2: Revenue Cap Formulae

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

2. $TAR_t = AR_t + I_t + B_t + C_t$ t = 1, 2..., 5

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

Where:

TAR_t is the total annual revenue in 2018-19.

p_t^{ij} is the price of component ‘j’ of tariff ’i' in 2018-19.

q_t^{ij} is the forecast quantity of component ‘j’ of tariff ‘i' in 2018-19.

AR_t is the annual smoothed expected revenue for 2018-19.

I_t is the final carryover amount from the application of the DMIS from the 2010–15 distribution determination.[12]

B_t is the sum of:

- any under or over recoveries relating to capital contributions from 2013–14 and 2014–15.[13]
- any under or over recovery of actual revenue collected through DUoS charges in regulatory year t–2 (i.e. 2016-17) as calculated using the method in appendix A of Attachment 14 of the Distribution Determination.

C_t is the sum of adjustments related to:

[12] This adjustment was only applicable to the 2016-17 Pricing Proposal and is not applicable to remaining years of the regulatory control period

[13] This adjustment is no longer applicable from 1 July 2017.

- feed-in tariff pass through amounts relating to the 2013–14 and 2014–15 regulatory years[14]
- any AER approved cost pass through amounts during the 2015–20 regulatory control period.

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 the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1
>
> divided by
>
> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2
>
> minus one.

For example, for the 2018–19 year, t–2 corresponds to December quarter 2016 and t–1 corresponds to December quarter 2017.

X_t is the X factor for each year of the 2015–20 regulatory control period as determined in the PTRM, and annually revised for the return on debt update in accordance with the formula specified in Attachment 3 – Rate of return[of the Distribution Determination, calculated for the relevant year.

S_t is the s-factor determined in accordance with the Service Target Performance Incentive Scheme (STPIS) for regulatory year t.

In addition to the TAR, transmission charges[15] and jurisdictional scheme amounts (including FiT payments made under the Solar Bonus Scheme (SBS) and the AEMC levy)[16] are also recovered from customers.

The details of our revenue requirement for 2018-19 are presented in Table 3-1.

Table 3-1: 2018-19 Total Revenue calculations

Components	Amount ($m)	Comments
(a) Annual Revenue (AR_{t-1})	$1,341.8	2017-18 annual smoothed expected revenue as per the amount in the approved 2017-18 Pricing Proposal.
(b) Consumer Price Index (CPI_t)	1.91%	Annual percentage change in the CPI All Groups, Average of Eight Capital Cities from the December quarter in 2016 to the December quarter in 2017 as published on the Australian Bureau of Statistics (ABS) website.
(c) X Factor (X_t)	2.55%	X factor for 2018-19 updated as a result of the annual return on debt update, as determined by the AER.
(d) STPIS (S_t)	0.006%	S-factor determined in accordance with the STPIS requirements. It is based on Ergon

14 This adjustment is no longer applicable from 1 July 2017.

15 Transmission charges are also known as DPPC or Transmission Use of System (TUoS) charges.

16 Jurisdictional scheme amounts will not be passed through to customers until at least 2020 as per the direction from the Queensland Government.

Components	Amount ($m)	Comments
		Energy's annual performance for 2016-17.
Impact on Revenue	***-$9.21***	***Impact = (a)x(1+(b))(1-(c))(1+(d))-(a)***
Annual Smoothed Expected Revenue 2018-19 (AR_t)	**$1,332.59**	
Adjustments:		
DMIS carryover amount (It)	N/A	No longer applicable.
DUoS under/over recoveries (B_t)	-$45.97	Over recovery for 2016-17 returned to customers. Further information is provided in Table 3-2.
Capital contribution under recoveries (B_t)	N/A	No longer applicable.
Solar Bonus Scheme (SBS) FiT payment pass through (C_t)	-$2.46	Reversal of the over-recovery of the SBS FiT payment pass through for 2014-15 period recovered in 2016-17. The amount has been adjusted by escalating by the WACC for 2017-18 and 2018-19.
Total Annual Revenue (TAR_t)	**$1,284.15**	
Jurisdictional Schemes	Nil	Includes Queensland SBS Jurisdictional Scheme and AEMC levy amounts. On 31 May 2017 Energex received a direction from the Queensland Government not to pass on the jurisdictional scheme charges to customers in our network tariffs until at least 2020.
TUoS (or DPPC)	$256.24	Transmission costs to be recovered in 2018-19
Total Revenue Requirement	**$1,540.39**	**Total revenue that Ergon Energy will need to recover in 2018-19.**

DUoS unders and overs account

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

Under these arrangements there is generally a two year lag between the year in which the DUoS under or over recovery occurs and the year in which adjustments are made to prices to 'clear' the under or over recovery. For example, the 2018-19 prices will include an adjustment relating to actual under or over recoveries which occurred in the 2016-17 regulatory year.

Consistent with the Distribution Determination (Attachment 14), we are required to:

- maintain a DUOS unders and overs account in our annual pricing proposal
- provide entries in the DUoS unders and overs account for the most recently completed regulatory year (t-2) and the next regulatory year (t). For this Pricing Proposal, year t-2 is 2016-17 and year t is 2018-19.[17]

The AER also requires that Ergon Energy's DUoS amounts for the most recently completed regulatory year t-2 (i.e. 2016-17) be audited. We believe this requirement is met as the information provided is based on the

[17] AER, Final Decision Ergon determination 2015-16 to 2019-20, Attachment 14 – Control Mechanisms, October 2015.

information lodged (and audited) as part of the Annual Reporting Regulatory Information Notice (RIN). It should be noted that the amounts for the next regulatory year (t) are forecast amounts.

The unders and overs account is detailed in Table 3-2 below.

Table 3-2: Calculation of DUOS unders and overs account

	2016-17 Year t-2 (actual) $'000	2018-19 Year t (forecast) $'000
(A) Revenue from DUOS charges[1]	$1,504,085	$1,284,140
(B) Less TAR for regulatory year =	$1,463,200	$1,284,147
+ Annual revenues (AR_t)	$1,157,524	$1,332,578
+ DMIS carryover amount (I_t)	($2,576)	$0
+ Sum of under or over recoveries (B_t) =	$180,184	($45,975)
+ Capital contributions/shared assets	*$108,129*	*$0*
+ DUOS revenue under/over recovery approved	*$72,055*	*($45,975)*
+ Sum of pass through adjustments (C_t) =	$128,068	($2,456)
+ Feed-in tariff cost pass throughs	*$128,068*	*($2,456)*
+ Approved pass through amounts	*$0*	*$0*
(A minus B) Under/over recovery of revenue for regulatory year[2]	$40,885	($8)
DUOS unders and overs account		
Nominal WACC t-2 (per cent)	6.04%	
Nominal WACC t-1 (per cent)	6.04%	
Opening balance	$0	$45,975
Interest on opening balance for 1 regulatory year	$0	n/a
Under/over recovery of revenue for regulatory year	$40,885	($45,975)
Interest on under/over recovery for 2 regulatory years	$5,090	n/a
Closing balance[2]	$45,975	($8)

Note:
1. For 2016-17, reflects actual revenue from DUOS charges as reported in the 2016-17 Annual Reporting RIN.
2. Difference between the 2018-19 TAR and forecast revenue from network charges is due to rounding of rates.

3.2.2 Revenue allocation

Rule requirement

Clause 6.18.1A Tariff structure statement

(a)(5) A *tariff structure statement* of a Distribution Network Service Provider must include a description of the approach that the *Distribution Network Service Provider* will take in setting each tariff in each *pricing proposal* of the *Distribution Network Service Provider* during the relevant *regulatory control period* in accordance with clause 6.18.5 (Pricing Principles).

Consistent with clause 6.18.1A(a)(5) of the NER, Chapter 4 of our TSS contains a description of the process we undertake each year to establish our network tariffs, including how we allocate the TAR to various network user groups and convert it into cost reflective tariffs to the extent possible considering customer impact.

We have applied the approach set out in our TSS in establishing 2018-19 tariffs in this Pricing Proposal.

3.2.3 Recovery of DUOS charges from generators

Rule requirement

Clause 6.1.4 Prohibition of DUOS charges for the export of electricity

(a) A *Distribution Network Service Provider* must not charge a *Distribution Network User distribution use of system* charges for the export of electricity generated by the user into the distribution network.

(b) This does not, however, preclude charges for the provision of *connection services*.

We note that clause 6.1.4(a) of the NER specifically prohibits DUOS charges being applied for the export of electricity generated by the user into our distribution network.

As outlined in Table 2-2 and Chapter 5 of our TSS, EGs will not incur DUOS charges for the export of electricity generated by the user into the distribution network. However, a DUOS fixed charge ($/day) applies to EGs. This charge reflects costs associated with connection assets and network user management services provided to EGs. These costs are incurred regardless of whether the EG exports electricity into our network. Furthermore, EGs who are net importers of electricity will receive network charges only for their use of the network related to the electricity import. Where customers are net generators and are exposed to kVA based demand charges, their export will be ignored in the calculation of their demand charges.

In the case of SACs with micro-generation facilities, these customers are assigned to the same network tariff for supply to their connection point as any other network customer with a similar load profile (i.e. in the absence of micro-generation facilities). They will however only receive DUOS charges for their use of the network related to electricity import.

3.2.4 Forecast weighted average revenue

Rule requirement

Clause 6.18.2 Pricing Proposals

(b)(4) A *pricing proposal* must 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*.

In accordance with clause 6.18.2(b)(4) of the NER, the expected weighted average revenue related to Ergon Energy's Standard Control Services tariff classes for 2017-18 and 2018-19 is shown in Table 3-3 below.

Table 3-3: Weighted average revenue for Standard Control Services

Tariff class	2017-18	2018-19	Change in weighted in average revenue
ICC – East	$41,667,142	$35,078,213	-15.8%
ICC – West	$14,472,611	$13,820,567	-4.5%
ICC – Mount Isa	$0	$0	0.0%
CAC – East	$72,195,786	$69,403,211	-3.9%
CAC – West	$9,125,752	$7,337,078	-19.6%
CAC – Mount Isa	$0	$0	0.0%
EG – East	$2,665,267	$2,509,582	-5.8%
EG – West	$1,039,832	$1,019,194	-2.0%
EG – Mount Isa	$0	$0	0.0%
SAC Large (>100 MWh p.a.) – East	$299,964,398	$281,358,286	-6.2%
SAC Large (>100 MWh p.a.) – West	$77,661,270	$73,966,238	-4.8%
SAC Large (>100 MWh p.a.) – Mount Isa	$4,452,592	$4,173,947	-6.3%
SAC Small (<100 MWh p.a.) – East	$624,222,245	$594,494,322	-4.8%
SAC Small (<100 MWh p.a.) – West	$186,421,693	$176,215,389	-5.5%
SAC Small (<100 MWh p.a.) – Mount Isa	$9,542,828	$9,133,360	-4.3%
SAC Unmetered – East	$13,756,444	$13,144,358	-4.4%
SAC Unmetered – West	$2,332,533	$2,206,818	-5.4%
SAC Unmetered – Mount Isa	$269,624	$253,115	-6.1%

Note: all amounts are GST exclusive

3.2.5 Side constraints

Rule requirement

Clause 6.18.6 Side constraints on tariffs for standard control services

(a) This clause applies only to tariff classes related to the provision of standard control services.

(b) The expected weighted average revenue to be raised from a *tariff class* for a particular *regulatory year* of a *regulatory control period* must not exceed the corresponding expected weighted average revenue for the preceding *regulatory year* in that *regulatory control period* by more than the permissible percentage.

Distribution Determination requirement

Attachment 14 – Ergon Energy's revenue from each tariff class must be consistent with the formula in Figure 14.2

Clause 6.18.6(b) of the NER and the requirements set out by the AER in its Distribution Determination require the expected weighted average revenue from DUOS to be raised from each tariff class in year (t) to not exceed the corresponding expected weighted average revenue from the preceding year (t-1) by more than a permissible percentage determined as per the side constraint formula below.

In determining whether the permissible percentage, we have applied the requirements set out in clause 6.18.6(d) of the NER and have excluded the following:

- the recovery of revenue relating to pass through costs
- the recovery of revenue relating to the pass through of DPPC
- the recovery of revenue relating to the pass through of jurisdictional schemes
- the recovery of revenue reflecting the annual update of the cost of debt.

The AER's Distribution Determination provides further guidance on side constraints by setting out the side constraint formula Ergon Energy's proposed DUoS revenue must comply with.

Equation 3.1: Side constraint formula

$$\frac{\left(\sum_{i=1}^{n}\sum_{j=1}^{m} d_t^{ij} q_t^{ij}\right)}{\left(\sum_{i=1}^{n}\sum_{j=1}^{m} d_{t-1}^{ij} q_t^{ij}\right)} \leq (1+\Delta CPI_t)\times(1-X_t)\times(1+2\%)\times(1+S_t)+I_t^{'}+B_t^{'}+C_t^{'}$$

where each tariff class has "n" tariffs, with each up to "m" components, and where:

d_t^{ij} is the proposed price for component 'j' of tariff 'i' for year t.

d_{t-1}^{ij} is the price charged for component 'j' of tariff 'i' in year t–1.

q_t^{ij} is the forecast quantity of component 'j' of tariff 'i' in year t.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1

divided by

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2

minus one.

X_t is the X factor for each year of the 2015–20 regulatory control period as determined in the PTRM, and annually revised for the return on debt update in accordance with the formula specified in Attachment 3 – Rate of return of the Distribution Determination – calculated for the relevant year. If X>0, then X will be set equal to zero for the purposes of the side constraint formula.

S_t is the s-factor determined in accordance with the STPIS for regulatory year t.

$I_t^{'}$ is the annual percentage change from the final carryover amount from the application of the DMIS from the 2010–15 distribution determination which was deducted from the allowed revenue in 2016–17but no longer applies to subsequent years.

$B_t^{'}$ is the annual percentage change from the sum of:

- any under or over-recoveries relating to capital contributions and shared assets from 2013–14 and 2014–15
- any under or over recovery of actual revenue collected through DUoS charges in regulatory year t–2 as calculated using the method in appendix A of Attachment 14 of the Distribution Determination.

This revenue adjustment is no longer applicable in 2018-19.

$C_t^{'}$ is the annual percentage change from the sum of adjustments related to:

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

The values used to calculate the permissible percentage for 2018-19 as per the side constraint formula are provided in Table 3-4 below.

Table 3-4: 2018-19 values used in the side constraint formula

Components	2018-19
ΔCPI_t	1.909%
Min (X_t,0)	0.000%
S_t	0.006%
$I_t^{'}$	0.000%
$B_t^{'}$	-0.034%
$C_t^{'}$	0.000%
Permissible percentage:	**0.392%**

Table 3-5 confirms that the weighted average revenue to be raised from each tariff class in 2018-19 is below the percentage allowed by the side constraint formula (i.e. the permissible percentage threshold of 0.39 per cent).

Table 3-5: Compliance with side constraint formula

Tariff class	Calculated percentage change between 2017-18 and 2018-19	Permissible percentage change
ICC – East	-15.8%	0.39%
ICC – West	-4.5%	0.39%
ICC – Mount Isa	0.0%	0.39%
CAC – East	-3.9%	0.39%
CAC – West	-19.6%	0.39%
CAC – Mount Isa	0.0%	0.39%

Tariff class	Calculated percentage change between 2017-18 and 2018-19	Permissible percentage change
EG – East	-5.8%	0.39%
EG – West	-2.0%	0.39%
EG – Mount Isa	0.0%	0.39%
SAC Large (>100 MWh p.a.) – East	-6.2%	0.39%
SAC Large (>100 MWh p.a.) – West	-4.8%	0.39%
SAC Large (>100 MWh p.a.) – Mount Isa	-6.3%	0.39%
SAC Small (<100 MWh p.a.) – East	-4.8%	0.39%
SAC Small (<100 MWh p.a.) – West	-5.5%	0.39%
SAC Small (<100 MWh p.a.) – Mount Isa	-4.3%	0.39%
SAC Unmetered – East	-4.4%	0.39%
SAC Unmetered – West	-5.4%	0.39%
SAC Unmetered – Mount Isa	-6.1%	0.39%

3.2.6 Avoidable and stand-alone costs

Rule requirement

Clause 6.18.5 Pricing principles

(e) For each *tariff class*, the revenue expected to be recovered must lie on or between:

(1) an upper bound representing the stand alone cost of serving the *retail customers* who belong to that class; and

(2) a lower bound representing the avoidable cost of not serving those *retail customers*.

In accordance with clause 6.18.5(e) of the NER, the revenue expected to be recovered from each tariff class should lie on or between the bounds of stand-alone and avoidable costs.

As noted in our TSS, we interpret these costs in the following manner:

- **Stand-alone costs** for a tariff class are the theoretical costs of establishing and maintaining infrastructure to service a single tariff class as if no other tariff classes needed to be served. 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 and scope from using a shared network to serve customers across multiple tariff classes are ignored.
- **Avoidable costs** are the costs which would be avoided by Ergon Energy not providing a distribution service to a particular tariff class, assuming all other tariff classes continued to be served. For example, if we were to cease providing services to CACs in our West Zone, the avoidable cost methodology assesses the extent to which our costs would be reduced as a result.

By requiring revenue from each tariff class to lie between stand-alone and avoidable costs, the regulatory framework ensures that each class of customers will be allocated the efficient costs of the network services they require.

Details of our approach to determining the avoidable and stand-alone costs for our Standard Control Services are provided in Chapter 6 and Appendix C of our TSS.

Table 3-6 below demonstrates that our total revenue for 2018-19 from each tariff class falls between the stand-alone and avoidable cost estimates.[18]

Table 3-6: Avoidable costs, expected revenue and stand- alone costs for Standard Control Services for 2018-19

Tariff class	Avoidable costs	Expected revenue	Stand alone costs	Clause 6.18.5(e) compliance
ICC – East	$17,727,503	$35,078,213	$234,534,265	Yes
ICC – West	$1,951,282	$13,820,567	$28,501,279	Yes
ICC – Mount Isa	$0	$0	$0	Yes
CAC – East	$25,323,021	$69,403,211	$254,872,289	Yes
CAC – West	$186,208	$7,337,078	$25,951,658	Yes
CAC – Mount Isa	$0	$0	$0	Yes
EG – East	$0	$2,509,582	$41,435,627	Yes
EG – West	$0	$1,019,194	$11,422,613	Yes
EG – Mount Isa	$0	$0	$0	Yes
SAC Large (>100 MWh p.a.) – East	$173,910,993	$281,358,286	$928,196,231	Yes
SAC Large (>100 MWh p.a.) – West	$47,544,120	$73,966,238	$255,877,048	Yes
SAC Large (>100 MWh p.a.) – Mount Isa	$3,397,074	$4,173,947	$12,556,723	Yes
SAC Small (<100 MWh p.a.) – East	$292,639,783	$594,494,322	$928,196,231	Yes
SAC Small (<100 MWh p.a.) – West	$96,495,750	$176,215,389	$255,877,048	Yes
SAC Small (<100 MWh p.a.) – Mount Isa	$5,837,374	$9,133,360	$12,556,723	Yes
SAC Unmetered – East	$6,544,439	$13,144,358	$539,363,208	Yes
SAC Unmetered – West	$1,804,114	$2,206,818	$25,935,692	Yes
SAC Unmetered – Mount Isa	$89,079	$253,115	$677,287	Yes

Note: all amounts are GST exclusive

[18] 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 National Electricity Law. The tariffs we assign to these customers recover the cost of dedicated connection assets for the generator and do not reflect their use of the shared network.

3.2.7 Long Run Marginal Cost

Rule requirement

Clause 6.18.5 Pricing principles

(f) Each tariff must be based on the *long run marginal cost* of providing the service to which it relates to the *retail customers* assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:

(1) the costs and benefits associated with calculating, implementing and applying that method as proposed;

(2) the additional costs likely to be associated with meeting demand from *retail customers* that are assigned to that tariff at times of greatest utilisation of the relevant part of the *distribution network*; and

(3) the location of *retail customers* that are assigned to that tariff and the extent to which costs vary between different locations in the *distribution network.*

The pricing principles in the NER require each tariff to be “based on” the LRMC of providing the service to the retail customers assigned to that tariff. The method of calculating and applying LRMC must have regard to a number of considerations specified in clause 6.18.5(f) of the NER.

It should be noted that neither the calculation of LRMC nor the application of LRMC to tariff-setting are prescribed in the NER and, therefore, can be undertaken in a number of different ways. Chapter 6 of our TSS and Appendix B of our *Supporting Information - Revised Tariff Structure Statement* set out the methodology we have adopted to calculate LRMC and our approach to incorporating these values in our tariff structures and rates.

Application of LRMC in tariff-setting

In our tariff-setting for 2018-19 we have applied the approach to LRMC detailed in our TSS. As noted in our TSS, Ergon Energy’s suite of network tariffs includes:

- Selection of appropriate charging parameter: The LRMC values have been incorporated in the demand charge parameter of the demand based tariffs as it is considered the most suitable mechanism to signal the cost of future network augmentation. For the tariffs without a demand charge parameter, LRMC has been allocated to the peak usage charge of time-of-use usage tariffs and the flat usage charge of the anytime usage tariffs. For the proposed Lifestyle Tariff, LRMC is incorporated in both the capacity band and peak summer top-up charging parameters. It should be noted, however, for the first band of the Lifestyle tariff (network use allowance of 0 kWh per month), LRMC is fully allocated to the top-up charge.
- Strength of the LRMC signal:
  - For our ‘legacy tariffs’: these tariffs and associated tariff structures have been in place for many years and, therefore, do not reflect the LRMC signal in its pure form. Recognising the impact on customers, legacy tariffs are being gradually restructured to better reflect more efficient network usage signals than they previously did.
  - Cost reflective tariffs: for all tariff classes except ICC, we have introduced alternative optional seasonal time of use demand tariffs that customers can adopt through their choice of retail tariff. These ‘LRMC-based tariffs’ place a higher and more appropriate weight on signaling the LRMC of using the distribution network at peak times.

Table 3-7 below provides the level of LRMC applied to the peak charging component for each customer class for 2017-18 and 2018-19.

Table 3-7: LRMC charges for Standard Control Services

Customer class	Zone	2017-18		2018-19	
		Calculated	Applied	Calculated	Applied
SAC		$/kW p.a.			
SAC Small Residential (STOUE & STOUD)	East	300.00	228.66	300.00	234.38
	West	751.00	572.41	751.00	586.72
	Mount Isa	304.00	228.58	304.00	234.29
SAC Small Business (STOUE & STOUD)	East	300.00	284.16	300.00	291.26
	West	751.00	711.35	751.00	729.13
	Mount Isa	304.00	284.06	304.00	291.16
SAC Large (STOUD)	East	300.00	168.72	300.00	172.94
	West	751.00	422.36	751.00	432.92
	Mount Isa	304.00	168.66	304.00	172.88
CAC		$/kVA p.a.			
22/11 kV Line (STOUD)	East	217.00	217.00	217.00	217.00
	West	543.00	543.00	543.00	543.00
22/11 kV Bus (STOUD)	East	132.00	115.50	132.00	121.28
	West	330.00	330.00	330.00	330.00
Higher Voltage (STOUD)	East	33.00	33.00	33.00	33.00
	West	83.00	83.00	83.00	83.00

3.2.8 Least distortionary recovery of residual costs

Rule requirement

Clause 6.18.5 Pricing principles

(g) The revenue expected to be recovered from each tariff must:

(1) reflect the *Distribution Network Service Provider's* total efficient costs of serving the retail customers that are assigned to that tariff;

(2) when summed with the revenue expected to be received from all other tariffs, permit the *Distribution Network Service Provider* to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the *Distribution Network Service Provider*; and

(3) comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (f).

The pricing principles in the NER provide that we structure our tariffs in a manner that enables the recovery of our 'residual' costs while minimising distortions to LRMC-based signals.

In establishing the 2018-19 network tariffs, we confirm that it has been necessary to allocate residual costs, in order to recover the portion of the revenue cap that could not be fully recovered through LRMC-based charging parameters. This means that we have to recover the revenue shortfall through the fixed, capacity, off-peak demand and volume parameters. Residual recovery within each customer group has been based on selecting combinations that minimise distortion of the LRMC signal.

Chapter 6 of the TSS further discusses how our tariff structures ensure we recover our revenue allowance in the least distortionary way, consistent with clause 6.18.5(g) of the NER.

3.2.9 Tariff simplicity

Rule requirement

Clause 6.18.5 Pricing Principles

(i) The structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff, having regard to:

(1) The type and nature of those retail customers; and

(2) The information provided to, and the consultation undertaken with those retail customers.

The structures of our tariffs have been developed in consideration to the feedback received as a result of the ongoing engagement with our customers and stakeholders as part of the development of our TSS. We consider that our tariffs strike the right balance between cost reflectivity and customers' ability to understand and respond to the pricing signals.

3.3 Designated pricing proposal (or TUOS) charges

Rule requirement

Clause 6.18.7 Recovery of designated pricing proposal charges

(a) A *pricing proposal* must provide for tariffs designed to pass on to *retail customers* the *designated pricing proposal charges* to be incurred by the *Distribution Network Service Provider*.

Clause 6.18.2 Pricing Proposals

(b)(6) A *pricing proposal* must set out how *designated pricing proposal charges* are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those charges in the previous *regulatory year*.

3.3.1 Background

Under the NER, we are able to recover transmission-related costs associated with:

- the use of Powerlink's transmission network to deliver high voltage electricity from generators to our network
- Avoided transmission (TUOS) charges paid to eligible EGs[19]
- payments made to other DNSPs for the supply of distribution services. For Ergon Energy, this includes our connection to Energex's network at Postman's Ridge.

In addition, Attachment 14 of the Distribution Determination allows us to pass through the entry and exit services charged by Powerlink for the three connection points listed in Section 3.3.2 below.

These costs are recovered from customers through DPPC, or 'TUOS' charges, which form part of our network tariffs.

In accordance with clauses 6.18.2(b)(6) and 6.18.7(b) of the NER, the DPPC amount to be passed on to customers must not exceed the estimated amount of the DPPC adjusted for any over or under recovery.

[19] Ergon Energy makes Avoided TUoS payments to EGs that have sought access to Ergon Energy's distribution network under clause 5.5 of the NER, and who meet other requirements set out in our Information Guide for Standard Control Services Pricing. This document is available on Ergon Energy's website at: www.ergon.com.au/network/network-management/network-pricing.

Consistent with clause 6.18.7(d) of the NER, we confirm that our DPPC (TUOS) charges do not include any amounts relating to our revenue requirement, jurisdictional schemes or any other amounts recovered from another DNSPs.

3.3.2 Transmission costs (expenses)

Designated pricing proposal charges paid to TNSPs (Powerlink)[20]

Powerlink charges Ergon Energy at the Transmission Connection Point level. Their charges comprise both daily supply and variable components, namely:

- 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).

Powerlink also charges Ergon Energy for the entry and exit services at three connection points – Stoney Creek, Kings Creek and Oakey Town.[21]

Payments to other DNSPs

In the Toowoomba area, we take supply from Energex at its Postman's Ridge Transmission Connection Point and distributes to a group of customers in the area. This is done on economic grounds. Energex bills Ergon Energy a network service charge for these network services. These charges are forecast each year and are added to the Powerlink charges at our Middle Ridge Transmission Connection Point. This occurs before the allocation process identified above.

In the Mount Isa Zone, we are charged for the use of the unregulated 220 kV network which supplies the Cloncurry township. These costs are passed through to all customers in the Mount Isa Zone via DPPC (TUOS) charges, using an allocation method similar to that applied to Powerlink charges in the other TUOS Regions.

[20] Includes the entry and exit services charged by Powerlink for the three connection points described above.

[21] Treated as a designated pricing proposal charge to be paid to a Transmission Network Service Provider (TNSP) for the purposes of the TUOS unders and overs account.

3.3.3 Avoided TUOS charges

Rule requirement

Clause 5.5 Access arrangements relating to Distribution Networks

(h) A Distribution Network Service Provider must pass through to a Connection Applicant the amount calculated in accordance with paragraph (i) for the locational component of prescribed TUoS services that would have been payable by the Distribution Network Service Provider to a Transmission Network Service Provider had the Connection Applicant not been connected to its distribution network ('avoided charges for the locational component of prescribed TUoS services').

(i) To calculate the amount to be passed through to a Connection Applicant in accordance with paragraph (h), a Distribution Network Service Provider must, if prices for the locational component of prescribed TUOS services were in force at the relevant transmission network connection point throughout the relevant financial year:

(1) determine the charges for the locational component of prescribed TUOS services that would have been payable by the Distribution Network Service Provider for the relevant financial year:

(i) where the Connection Applicant is an Embedded Generator, if that Embedded Generator had not injected any energy at its connection point during that financial year;

(ii) where the Connection Applicant is a Market Network Service Provider, if the Market Network Service Provider had not been connected to the Distribution Network Service Provider's distribution network during that financial year; and

(2) determine the amount by which the charges calculated in subparagraph (1) exceed the amount for the locational component of prescribed TUOS services actually payable by the Distribution Network Service Provider, which amount will be the relevant amount for the purposes of paragraph (h).

Where we are liable to pay an Avoided TUOS payment to an EG in accordance with clause 5.5(h) and (i) of the NER, the payment amount is recovered as part of the TUOS volume charges passed through to customers at the same connection point as the EG.

Payments associated with avoided TUOS to eligible EGs by Ergon Energy reflect the avoided costs of upstream transmission network reinforcement. In accordance with the NER, to calculate the avoided TUOS payments for eligible EGs, we will:

(1) determine the charges for the location component of prescribed DPPC services that would have been payable by Ergon Energy had the EG not injected any energy at its connection point during that financial year.

(2) determine the amount by which the charges calculated in (1) exceeds the amount for the locational component of prescribed DPPC (services actually payable by Ergon Energy.

(3) credit the value from (2) to the EG account.

For 2018-19, avoided TUOS payments will generally be remitted in the form of a lump sum payment after 30 June 2019.

The estimated total amount in avoided TUOS liability to EGs accrued in 2018-19 is included in Table 3-8 below.

Further information on how we determine Avoided TUOS payments under clause 5.5(h) and (i) of the NER is set out in our Information Guide for Standard Control Services Pricing available on the Ergon Energy website.[22]

3.3.4 Recovery of transmission costs (revenue)

Our network tariff calculation process allocates the transmission cost components, on a cost reflective basis, to Ergon Energy's TUOS charging structures. This conversion is shown in our Information Guide for Standard Control Services Pricing.

We then apportion these charges to customers and/or customer groups on the following basis:

- customer numbers for the Entry/Exit Connection Price
- forecast any time maximum demand (ATMD) for the Usage Capacity Price
- forecast energy use for the remaining components.

For SAC Small, SAC Large and CACs, Transmission Connection Points are allocated to one of three geographical TUOS Regions. TUOS charges are then calculated based on the combined totals. This has the advantage of simplifying tariffs, while still providing clear TUOS locational signals for these customers.

For those CACs that have a primary and alternate supply (as deemed by Ergon Energy), the following TUOS arrangements apply:

- Primary supply – standard rates and conditions for each charge
- Alternate supply – standard rates and conditions for each charge, except:
  - no TUOS fixed charge applies
  - the authorised demand for the TUOS capacity charge is set at zero.

This means, with the exception of the TUOS fixed charge, alternate supplies to customers are charged at the standard rates (applicable to the voltage of the connection) for all metered quantities. However, with an authorised demand set at zero for the alternate connection, the capacity charge will only apply to the ATMD in any month when a changeover to the alternate supply takes place.

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

TUOS charges for CACs and ICCs are presented in kVA.

[22] This document is available on Ergon Energy's website at: www.ergon.com.au/network/network-management/network-pricing

3.3.5 DPPC (TUOS) unders and overs account

Rule requirement

Clause 6.18.7 Recovery of designated pricing proposal charges

(b) The amount to be passed on to *retail customers* for a particular *regulatory year* must not exceed the estimated amount of the *designated pricing proposal charges* adjusted for over or under recovery in accordance with paragraph (c)

(c) The over and under recovery amount must be calculated in a way that:

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

Distribution Determination requirement

Attachment 14 – Ergon Energy must submit as part of its annual pricing proposal, a record of the amount of revenue recovered from designated pricing proposal charges and associated payments in accordance with appendix B of this attachment

In accordance with the NER and the AER's requirements set out in the Distribution Determination, we are required to maintain a DPPC unders and overs account which provides amounts for the revenue recovered from DPPC (TUOS) charges and associated payments to Powerlink for the most recently completed regulatory year (t-2) and the next current regulatory year (t). This annual unders and overs process ensures that any difference between the revenue recovered from customers and the actual transmission-related expenses is returned to (or recovered from) our customers so that we recover no more and no less that the DPPC (TUOS) amounts we incurred.

The unders and overs account in Table 3-8 below sets out Ergon Energy's 2016-17 over recovery based on information lodged and audited in our 2016-17 RIN.

DPPC amounts for the regulatory year (t) are forecast amounts.

Table 3-8: Calculation of DPPC unders and overs account

	2016-17 Year t-2 (actual) $'000	2018-19 Year t (forecast) $'000
(A) Revenue from designated pricing proposal charges (DPPC)	$393,291	$256,237
(B) Less DPPC related payments for regulatory year =	$393,050	$256,237
+ DPPC charges to be paid to TNSP	$378,571	$248,814
+ Avoided TUOS payments	$3,139	$2,207
+ Inter–distributor payments	$5,259	$5,486
+ DPPC revenue under/over recovery approved	$6,081	($271)
(A minus B) Under/over recovery of revenue for regulatory year	$241	$0
DPPC unders and overs account		
Nominal WACC t-2 (per cent)	6.04%	
Nominal WACC t-1 (per cent)	6.04%	
Opening balance	$0	$271
Other adjustments to opening balance approved by regulator	$0	n/a
Interest on opening balance for 1 regulatory year	$0	n/a
Under/over recovery of revenue for regulatory year	$241	($271)
Interest on under/over recovery for 2 regulatory years	$30	n/a
Closing balance	$271	$0

3.4 Jurisdictional scheme charges

Rule requirement

Clause 6.18.7A Recovery of jurisdictional scheme amounts

(a) A *pricing proposal* must provide for tariffs designed to pass on to customers *Distribution Network Service Provider's jurisdictional scheme amounts* for *approved jurisdictional schemes*.

Clause 6.18.2(b)(6A) A *pricing proposal* must set out how *jurisdictional scheme amounts* for each *approved jurisdictional scheme* are to be passed on to customers and any adjustments to tariff resulting from over or under recovery of those amounts

Clause 6.18.2(b)(6B) A *pricing proposal* must describe how each *approved jurisdictional scheme* that has been amended since the last *jurisdictional scheme approval date* meets the *jurisdictional scheme eligibility criteria*.

In accordance with clause 6.18.2(b)(6A) of the NER, our pricing proposal must 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.

Jurisdictional schemes are certain programs implemented by state governments that place legislative obligations on DNSPs. The jurisdictional schemes we are subject to comprise:

- the Solar Bonus Scheme which obligates Ergon Energy to make FiT payments for energy supplied into our distribution network from specific micro-embedded generators[23]
- the energy industry levy covering a proportion of the Queensland Government's funding commitments for the AEMC which, under our Distribution Authority, we are obligated to pay since 2016.

It should be noted that on 1 June 2017 the Queensland Government directed us to remove the jurisdictional scheme amounts (Solar Bonus Scheme and other amounts) from our network charges until at least 2020. These costs are funded by the Queensland Government instead of electricity customers via a fixed grant covering the estimated jurisdictional scheme amounts covering the three year period from 1 July 2017 to 30 June 2020. As a result, the jurisdictional scheme rates in our 2018-19 network charges have been set to zero.

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

3.4.1 Jurisdictional scheme unders and over account

Rule requirement

Clause 6.18.7A Recovery of jurisdictional scheme amounts

(b) The amount to be passed on to customers for a particular *regulatory year* must not exceed the estimated amount of the *jurisdictional scheme amounts* for a *Distribution Network Service Provider's approved jurisdictional schemes* adjusted for over or under recovery in accordance with paragraph (c)

(c) The over and under recovery amount must be calculated in a way that:

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

Distribution Determination requirement

Attachment 14 – Ergon Energy must maintain in its annual pricing proposal a jurisdictional scheme amounts unders and overs account recovery in accordance with appendix C of this attachment.

As part of the requirements set out in the NER and the AER's Distribution Determination, we are required to provide amounts for the unders and overs relating to jurisdictional schemes for the most recently completed regulatory year t-2, being 2016-17, and the regulatory year t, being 2018-19.

The unders and overs account presented in Table 3-9 below is based on information lodged (and audited) in our 2016-17 RIN.

Table 3-9: Calculation of jurisdictional scheme unders and overs account

	2016-17 Year t-2 (Actual) $'000	2018-19 Year t (Forecast) $'000
(A) Revenue from jurisdictional schemes	$106,861	$88,354
(B) Less jurisdictional scheme payments for regulatory year =	$100,237	$95,802
+ Jurisdictional scheme payments (Solar Bonus Scheme)	$100,153	$95,695
+ Jurisdictional scheme payments (Energy industry levy)	$84	$107
+ Jurisdictional scheme amounts revenue under/over recovery approved	$0	n/a
(A minus B) Under/over recovery of revenue for regulatory year	$6,624	($7,448)
Jurisdictional scheme amount unders and overs account		
Nominal WACC t-2 (per cent)	6.04%	
Nominal WACC t-1 (per cent)	6.04%	
Opening balance	$0	$7,448
Interest on opening balance for 1 regulatory year	$0	n/a
Under/over recovery of revenue for regulatory year	$6,624	($7,448)
Interest on under/over recovery for 2 regulatory years	$825	n/a
Closing balance	$7,448	$0

3.4.2 Forecast of jurisdictional scheme amounts

The estimated jurisdictional scheme amount to be recovered in 2018-19 is $88,354 million. It comprises $95,695 million in SBS FiT payments, $7,448 million in over recovery, and $0.11 million in AEMC levy. As demonstrated in Table 3-10 below, this amount will not be passed on to customers through our network charges but will instead be covered by a proportion of the Queensland Government's grant.

Table 3-10: Forecast for 2018-19 SBS FiT payments

SBS FiT Payment calculation	2018-19
Solar FiT Payment ($M)	**$95,695**
Over recovery[a]	($7,488)
Total Solar Fit Payment ($M)	**$88,247**
AEMC Levy	0.11
Total Jurisdictional Scheme amount	**$88,354**
Portion of the Qld Government Grant	$88,354
Balance	**$0**

Note:
a. Refer to Table 3-9 for further details.

The jurisdictional scheme amount to be recovered from customers in 2018-19 through the network tariffs is nil and will appear as a zero charge.

3.5 Demand, energy and customer number forecasts

Rule requirement
Clause 6.18.8(a)(3) Approval of pricing proposal
The *AER* must approve a *pricing proposal* if the *AER* is satisfied that, all forecasts associated with the proposal are reasonable.

Each year we prepare a forecast of customer numbers, demand and energy consumption for preparation of our Pricing Proposal. An initial forecast is prepared in October which is later refined up until February of the following year based on the most up to date information available prior to preparation of the annual Pricing Proposal.

Energy and maximum demand forecasts for major customers (ICCs and CACs) are individually developed. The energy forecast is based on a review of each customer's recent actual consumption history plus any confirmed future operational changes. The forecast demand for major customers is either:

- negotiated with the network user and detailed in their connection contract ('contracted demand'); or
- based on a review of actual demand history, with adjustments reflecting up to date customer related information about additions or losses of load.

For new customers a flat usage or similar industry load profile is applied as appropriate until historical data for their connection is available.

For the SAC network user group, forecast energy consumption and customer numbers are based on a combination of econometric forecasts and trend extrapolation.

The forecast demand, energy and customer number for 2018-19 are included in Table 3-11 below.

Table 3-11: 2018-19 demand, energy and customer number forecast

Tariff class	ICC	CAC	SAC	EG	Total
Average Demand (MVA)	1,251	514	N/A	N/A	1,765
Average Maximum Demand (MW)	N/A	N/A	2,391	N/A	2,391
Volume (GWh)	3,695	1,394	8,507	0	13,596
Customer numbers	78	183	741,487	58	741,806

Note:
Average Maximum Demand is undiversified, assuming all customers are utilising the network at the same time.

3.6 2018-19 proposed standard control services charges

The proposed network charges to be adopted for our Standard Control Services in 2018-19 are set out in Attachment 1 of this Pricing Proposal.

Section 5.4 provides further explanation on the differences between our proposed 2018-19 tariffs and the corresponding indicative pricing levels developed as part of the 2017-18 annual pricing proposal process and included in the 2017-18 Indicative Pricing Schedule.

4 Alternative Control Services

Services provided under the Alternative Control Services framework are customer specific and/or customer requested services. These services may also have potential for provision on a competitive basis rather than by a single DNSP. Alternative Control Services are akin to a ‘user-pays’ system whereby the whole cost of the service is paid by those customers who benefit from it, rather than recovered from all customers.

Alternative Control Services are either price cap services (fee based services) for which the prices are set in accordance with specified service assumptions due to the standardised nature of the services, or a price on application (quoted services) whether the services are of a nature and scope which cannot be known in advance.

4.1 Tariff classes and tariffs

Rule requirement

Clause 6.18.3 Tariff classes

(b) Each customer for *direct control services* must be a member of 1 or more *tariff classes*

(c) Separate *tariff classes* must be constituted for *retail customers* to whom *alternative control services* are supplied.

(d) A *tariff class* must be constituted with regard to:

(1) the need to group *retail customers* together on an economically efficient basis; and

(2) the need to avoid unnecessary transaction costs.

As indicated in Section 2.1, 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). Being a subset of Direct Control Services, this obligation extends to Alternative Control Services. Further, clause 6.18.3(c) of the NER is met by Ergon Energy distinguishing between the tariff classes for Standard Control Services and for Alternative Control Services.

As outlined in clause 6.18.3(d)(1) and (2), the tariff classes for Alternative Control Services were developed having regard to the need to group customers together on an economically efficient basis, and the need to avoid unnecessary transaction costs. Compliance with this clause requires a balance between sending efficient price signals to individual customers and the cost of having too many tariff classes. As noted in our TSS, our tariff classes for Alternative Control Services are differentiated at the highest level according to the AER’s classification of services and the basis of pricing approved by the AER. Fee based services are further separated into two tariff classes based on the type of feeder to which a customer requesting the service is connected.

Aligning with the TSS, the Alternative Control Services tariff classes for 2018-19 are set out in Table 4-1 below.

Table 4-1: Ergon Energy's Alternative Control Service tariff classes

Tariff class
Fee based services (urban/short rural)
Fee based services (long rural/isolated)
Quoted services
Default Metering Services
Public Lighting Services

4.2 Tariffs and charging parameters

Rule requirement

Clause 6.18.2 Pricing Proposals

(b) A pricing proposal must:

(2) set out the proposed tariffs for each tariff class that is specified in the *Distribution Network Service Provider's* tariff structure statement for the relevant regulatory control period.

(3) set out for each proposed tariff, the charging parameters and the elements of service to which each charging parameter relates.

In accordance with clause 6.18.2(b)(1) of the NER, our Pricing Proposal sets out the Alternative Control Services which have been specified in our TSS.

In addition, clause 6.18.2(b)(3) of the NER requires that our Pricing Proposal sets out the charging parameters utilised to calculate the charges for Alternative Control Services and elements of service to which each charging parameter relates.

Ergon Energy's tariffs for Alternative Control Services are grouped according to the classification and basis of pricing determined by the AER in its Distribution Determination. 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 and which avoids unnecessary transaction costs as a result of tariff proliferation.

Tariff charging parameters

In accordance with clause 6.18.2(b)(3) of the NER, the charge and charging parameters that have been adopted for our 2018-19 Alternative Control Services tariffs are shown in Table 4-2 below and Attachment 1. These charges and charging parameters are consistent with those outlined in our TSS.

Table 4-2: Types of charges and charging parameters for Alternative Control Services

Service	Charge	Charging parameter
Fee based services	Fixed charge	Represented as a fixed rate ($) per service. Reflects the estimated cost of providing each service and varies depending on the type of service requested. Where call out fees apply, the fixed charge varies depending on the type of fee based service that the original call out was for
Quoted services	Quoted price	Represented as a quoted rate ($) per service. The quoted price varies based on actual resources required to

Service	Charge	Charging parameter
		deliver the type of service requested Where call out fees apply, the quoted price reflects actual costs incurred in attending the premises.
Default Metering Services	Fixed charge	Represented as a fixed rate ($) per day per meter. Within the tariff structure, metering service charges differ by: – the type of metering service (primary, controlled load, embedded generation); and – the type of cost recovery (capital, non-capital) For call outs associated with Default Metering Services[24] - a fixed rate ($) per call out applies
Public Lighting Services	Fixed charge and in some circumstances, a quoted price	*Daily public lighting charges* Represented as a fixed rate ($) per day per light. Within the tariff structure, daily public lighting charges differ by: – the ownership status (Ergon Energy owned and operated, or Gifted and Ergon Energy operated); and – the size of the lamp (major or minor lantern type) *Exit fees* Represented as a fixed rate ($) per light. Exit fees apply when a customer requests the replacement of an existing public light for a Light Emitting Diode (LED) light[25]. Exit fees are also distinguished by the ownership status and size of the lamp. *'Non-standard' public light charges* Represented as a quoted rate ($) per service. Non-standard public lighting charges apply where the cost of constructing public lights is not expected to be fully recovered through daily public lighting charges over a 20 year term. In these circumstances, Ergon Energy may require the customer to pay an additional upfront amount.

Alternative Control Services tariffs for each tariff class

In accordance with Clause 6.18.2(b)(2) of the NER, each of our Alternative Control Services tariffs for 2018-19 are set out in Attachment 1.

Chapter 11 of our TSS contains a description of the process we undertake each year to establish tariffs for Alternative Control Services. We have applied this approach in establishing the proposed 2018-19 Alternative Control Services tariffs set out in this Pricing Proposal.

[24] Ergon Energy has developed call out fees for final meter reads, which form part of the cost build-up of the non-capital metering charges. Costs of wasted attendance associated with final meter reads are recovered via a separate call out fee.

[25] Except where the proposed LED transition program is being implemented.

4.3 Control mechanisms

Ergon Energy's Alternative Control Services are regulated under a price cap control mechanism. This means the AER determines our efficient costs and approves a maximum price (or schedule of rates) that we can charge for the service.

Chapter 11 of our TSS sets out the process and methodology we follow each year to establish our prices for Alternative Control Services, including how we apply the price cap control mechanism formulae set out in the Distribution Determination. The approach to setting tariffs varies for each type of Alternative Control Service:

- For our *fee based services*, we have calculated a cost build-up price using the quoted services formula and a capped price using the fee based ancillary network services formula set out in the Distribution Determination. We then compare the price calculated under the cost build-up approach and price determined using the AER's price cap formula. The prices presented in this Pricing Proposal for AER-approval are the lower of these two amounts.
- For our *quoted services*, we have used the quoted services formula to develop illustrative prices. This formula will also be used in practice to develop actual prices for quoted services.
- For our *Default Metering Services* and *Public Lighting Services*, we have applied the relevant price cap formulae specified in the Distribution Determination. The exception to this is the public lighting exit fees, which have been escalated by inflation only.[26]

The calculation of our Alternative Control Service prices, including our compliance with the price cap control mechanism, is discussed below.

4.3.1 Control mechanism for fee based services

As outlined in our TSS, the price cap approach is applied to connection, ancillary network, auxiliary metering and other public lighting services and consists of the following two step process:

- A schedule of price capped Alternative Control Services for the first year of 2015-20 regulatory control period based on the cost build-up formula for quotes services (see Section 4.3.2 below) and using the efficient cost inputs approved by the AER.
- Prices in subsequent years of the regulatory control period 2015-20 are determined using the same cost build-up formula. However, we limit the annual price increases to the lower of the calculated amounts and the AER's price cap formula set out in Equation 4.1 below.

Equation 4.1 Control mechanism formula for price cap services

$$p_t^i = p_{t-1}^i(1+\Delta CPI_t)(1-X_t^i)+A_t^i$$

Where:

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

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

ΔCPI_t is the annual percentage change in the ABS CPI All groups, Weighted Average of Eight Capital Cities from the December quarter in year t-2 to the December quarter in year t-1.

X_t^i is the X factor for service i in year t

[26] The Distribution Determination did not provide detail on how the price cap formula should apply to public lighting exit fees. Ergon Energy worked with the AER to clarify how these charges should be calculated, and included the approach in our TSS. The AER approved our TSS on 28 February 2017.

A_t^i is an adjustment factor for residual charges when customers choose to replace assets before the end of their economic life.

In calculating the prices for 2018-19 price cap services, we used the CPI value of 1.91 per cent. We also applied the relevant X factors in accordance with the Distribution Determination.[27] These are summarised in Table 4-3 below.

Table 4-3: 2018-19 X factors and escalations for price capped services

Service Description	X factor %	Escalation %
Price Cap (fee based services)	(0.76)	2.68%
Upfront Meter Capital Charge	(0.46)	2.38%

Notes:
Escalation based on $(1+\Delta CPI_t)(1-X_t^i)+A_t^i$ as per the control mechanism formula in Equation 4-1 in this Pricing Proposal where CPI is 1.91% and A_t^i is nil.

We confirm that our 2018-19 charges for fee-based services have been set in accordance with the control mechanism formula in Equation 4.1 as this provides lower prices than those derived using the cost build-up formula.

Power of Choice review:

The AEMC's recommendations in the Power of Choice review was implemented in Queensland on 1 December 2017. Under these new arrangements, we are no longer responsible for providing metering installations as they are subject to contestability. We are only able to provide metering services to existing regulated meters as long as they are in operation. As a result, on 1 December 2017, a number of Alternative Control Services were either discontinued or had the metering provision component separated from the service with the remaining service components covering the services still performed by Ergon Energy.

It is important to note, that the new arrangements described above only apply to those parts of Ergon Energy's area of supply that are connected to the NEM. However, the metering related charges are still levied in the Mount Isa-Cloncurry and Isolated supply networks as Ergon Energy remains responsible for metering in these areas.

4.3.2 Control mechanism for quoted services

Prices for quoted services are determined at the time the customer makes an enquiry. They reflect the individual nature of the service requested and vary based on the resources required to deliver the type of services requested. To develop the prices for quoted services in 2018-19, we apply the AER approved formula outlined in Equation 4.2 below. This formula includes cost parameters for different services which are representative of the efficient costs of providing and delivering the services.

Equation 4.2: Formula for pricing quoted services

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

where:

Labour is all labour costs directly incurred in the provision of the service, labour on-costs, fleet on-costs and overheads. The labour cost for each service is dependent on the skill level, travel time, number of hours and

[27] AER, Final Decision Ergon Energy Determination 2015-20 to 2019-20, Attachment 16 – Alternative Control Services, Appendix A, October 2015.

crew size required to perform the service.

Contractor services is all costs associated with the use of external labour in the provision of the service, including overheads and any direct costs incurred as part of performing the service (e.g. traffic control, road closure permits).

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

Capital allowance is a return on, and return of, capital for non-system assets used in the delivery of the service.

4.4 Cost input changes for fee based and quoted services

In Chapter 11 of our TSS, we highlight that annual changes to cost inputs used in calculating prices for our fee based services and quoted services will be submitted to the AER for approval in our Pricing Proposal. Accordingly, the following sections set out the nature of these changes.

It is important to note that these adjustments impact the calculation of our fee based and quoted services prices in different ways. This is illustrated in Table 4-4.

Table 4-4: Impact of cost input changes on fee based and quoted services prices

Cost input	Impact on fee based services		Impact on quoted services	
	Capped price [a]	Cost build-up	Illustrative	Actual
Labour escalator	✗	✓	✓	✓
Fleet escalator	✗	✓	✓	✓
Materials escalator	✗	✓	✓	✗ [b]
Contractor services escalator	✗	✗ [c]	✓	✗ [b]
Labour on cost	✗	✓	✓	✓
Materials on cost	✗	✓	✓	✓
Overhead rates	✗	✓	✓	✓

Notes:

a. The capped price for each fee based service is not dependent on changes to the underlying cost inputs. Rather, the capped price is calculated in accordance with the price cap formula.
b. Ergon Energy will charge the actual costs incurred for Contractor Services and Materials, depending on the requirements of the job requested.
c. There are no Contractor Services used in the calculation of fee based services.

Escalators

We have adjusted the nominal labour, fleet, materials and contractor services escalators by annual CPI data to December quarter 2017 as published by the ABS.

Labour on costs

We have applied the same labour on cost rates for both ordinary time hours and overtime hours in comparison to those used in 2018-19 (43.5 per cent and 6.0 per cent respectively).

Materials on costs

The materials (stores) on cost rate in 2018-19 will remain at 16.6 per cent, consistent with the rate calculated and applied in 2017-18.

Overhead rates

Ergon Energy's also applies overhead rates in its calculation.

4.5 Control mechanisms for Default Metering and Public Lighting Services

For Default Metering and Public Lighting Services (provision, installation and maintenance), a limited building block approach is used to determine the allowable revenues over the regulatory control period, which are then converted in charges that are subject to a price cap. The charges for these services are developed using the control mechanism formula in Equation 4.1 and escalated from one year to the next based on changes in CPI and application of X and A factors (metering service charge).

Table 4-5: 2018-19 X factors and escalations for Default Metering and Public Lighting Services

Service Description	X factor %	Escalation %
Limited Building Block:		
Public Lighting	(4.52)	6.52
Metering Services Charge		
Non capital component	4.0	(2.17)
Capital component	(10.0)	12.1

Notes:
Escalation based on $(1+\Delta CPI_t)(1-X_t^i)+A_t^i$ as per the control mechanism formula in Equation 4-1 in this Pricing Proposal where CPI is 1.91% and A_t^i is nil.

4.6 Tariff assignment policies

As noted in Section 2.3, clause 6.18.1A(a)(2) of the NER requires our TSS to outline the policies and procedures we apply for assigning customers to tariffs classes and tariffs. Similar to our approach for Standard Control Services, we have developed a more detailed document containing our procedures on assigning and reassigning customer to Alternative Control Services tariff classes and tariffs. These procedures are published in Appendix E of our TSS. We will comply with these procedures in 2018-19.

As highlighted in Section 2.3, we must outline in this Pricing Proposal how we will review and assess the basis on which a customer is charged in certain circumstances. However, as the basis of charge and prices for Alternative Control Services is capped and/or developed using an approved formula, we consider 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, we consider that this requirement does not apply to our Alternative Control Services. Consequently, we do not need to assess or review the basis (the approved formulae and price caps) on which a customer is charged for Alternative Control Services.

4.7 Compliance with pricing principles

Ergon Energy's Alternative Control Services tariffs have been developed in accordance with the NER and our TSS. Details of our compliance with the pricing principles are provided below.

4.7.1 Avoidable and stand-alone costs

As noted in Section 3.2.6, clause 6.18.5(e) of the NER requires that for each tariff class, the revenue expected to be recovered should 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.

Our approach to determining the avoidable and stand-alone costs for our Alternative Control Services is set out in Section 12.2 of our TSS. Consistent with this approach, we have not undertaken any quantitative analysis of our stand-alone and avoidable costs for Alternative Control Services in 2018-19.

4.7.2 Long Run Marginal Cost

As noted in Section 3.2.7, clause 6.18.5(f) of the NER requires each tariff to be “based on” the long run marginal cost of providing the service to customers assigned to that class, with the method of calculating such costs and manner in which that method is applied, to be determined having regard to a number of factors.

Importantly, for Alternative Control Services, each tariff and the movement in tariffs between regulatory years are determined by the AER through the application of caps on the prices of individual services. The AER therefore determines the LRMC of each tariff when it establishes the initial prices and set the inputs, such as the X factors, to be used in the price cap formulae. 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. 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 principles.

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

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

Further information on how our Alternative Control Services take into account LRMC is provided in Section 12.3 of our TSS.

4.7.3 Recovery of residual costs

As discussed in Section 3.2.8, clause 6.18.5(g) of the NER provides that where tariffs based solely on LRMC do not enable Ergon Energy to recover efficient costs, we may structure tariffs to recover remaining ‘residual’ costs in a way that minimises distortions to LRMC-based signals.

We note that this rule is more applicable to our Standard Control Services. Furthermore, the AER, through its price cap control mechanism, sets the basis on which we are allowed to recover the efficient costs of providing each Alternative Control Service. The total amount of revenue recovered depends on the volume of services provided in the relevant year multiplied by the AER-approved rates (or schedule of rates, as is the case for quoted services).

4.8 2018-19 Alternative Control Services charges

The proposed charges for 2018-19 for all Alternative Control Services tariffs are included in Attachment 1 provided with this Pricing Proposal.

5 Other compliance

This chapter covers our compliance with the regulatory requirements which have not been covered in Chapters 2, 3 and 4 of this Pricing Proposal.

5.1 Customer considerations

5.1.1 Impact on retail customers

Rule requirement

Clause 6.18.5 Pricing principles

(h) A *Distribution Network Service Provider* must consider the impact on *retail customers* of changes in tariffs from the previous *regulatory year* and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the *Distribution Network Service Provider* considers reasonably necessary having regard to:

(1) the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one *regulatory control period*);

(2) the extent to which *retail customers* can choose the tariff to which they are assigned; and

(3) the extent to which *retail customers* are able to mitigate the impact of changes in tariffs through their usage decisions.

As evidenced below, we have been mindful of retail customer impacts when determining the manner in which, and speed with which, different tariffs should reflect the pricing principles contained in clauses 6.18.5(e) to (g) of the NER.

Standard Control Services

LRMC pricing principles provide for a two part tariff outcome with the first part promulgating the LRMC price signal and the second part addressing the residual revenue recovery. In developing the LRMC-based tariffs, our objective has been to present the LRMC component through parameters which are as cost reflective and least distortionary to the pricing signal as possible to enable customer responses that support optimal use of the network (refer Section 3.2.8).

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

Except for ICCs, customers have the option to move to more cost reflective LRMC-based tariffs. This provides customers with more choice and control in how they are charged for their use of the network.

Our TSS describes a number of measures we have taken to manage the impact of annual change to DUOS rates on individual customers, whilst moving toward a suite of tariffs that maximise achievement of the network pricing objective over the 2017 to 2020 period. These measures include:

- For our legacy tariffs:
  - As noted in Section 3.2.7, progressively incorporating the full LRMC into tariff rates while explicitly limiting adverse customer impacts
  - Applying constraints in tariff setting, such as constraining price impacts for tariff classes and setting maximum limits on the potential individual customer impacts.

- For our ‘opt-in’ LRMC-based tariffs:
  - Not adopting the full level of LRMC into tariff levels. Instead, we are adopting a transitioning approach which is expected to see the LRMC parameter progressively become stronger while the residual components are reduced
  - Developing and analysing a sample of customers to determine likely individual customer impacts on the alternative tariffs
  - Ensuring tariffs are attractive to customers who have the choice to move, or to stay on less efficient default tariffs.

In establishing the 2018-19 tariffs, we have continued to apply these measures.

Table 5-1 and Table 5-2 below present our customer impact analysis for 2018-19.

With ICC and CAC tariffs being confidential, we are not able to include a customer specific impact analysis. However, general trends in ICC and CAC customer impacts between 2017-18 and 2018-19 are presented in

Table 5-1. The average impact figures have been calculated based on the revenue we would recover using the 2018-19 approved rates relative to the revenue we would recover using the 2017-18 rates.

Table 5-1: Average customer impacts for the ICC and CAC tariff classes

Tariff classes	Impact	DUOS annual impact (%)	Jurisdictional Schemes annual impact (%)	TUOS annual impact (%)	NUOS annual impact (%)
ICC	Average impact	-4%	0%	-10%	-8%
CAC	Average impact	-4%	0%	-7%	-5%

In 2018-19, ICC and CAC customers will experience a decrease in their NUOS charges over the previous year with an average reduction of approximately 8 per cent for ICC customers and 5 per cent for CAC customers.

Analysis undertaken by Ergon Energy on the network price movements that may be experienced by customers on tariffs within the SAC tariff class is included in Table 5-2 below.

The network prices used for the customer impact analysis comprise total annual NUOS excluding GST. These NUOS prices are the AER approved prices for 2017-18 and the proposed 2018-19 prices included in Attachment 1 submitted with this Pricing Proposal for AER approval.

To eliminate the impact of fluctuation in demand and energy between years, the same usage and demand profiles were used to calculate customers’ bills for both 2017-18 and 2018-19.

Table 5-2: Customer impact for typical customers on a SAC tariffs

tariffs	Primary tariff - Usage (kWh/year)	Secondary tariff – Usage (kWh/year)	2017-18 NUOS ($)	2018-19 NUOS ($)	Annual NUOS increase/decrease ($)	Annual NUOS increase (%)
IBT Residential East (ERIB)	4,059		$742.9	$713.9	-$28.5	-4%
IBT Business East (EBIB)	6,334		$1,033.5	$991.5	-$42.0	-4%
IBT Residential East (ERIB) + Secondary tariff	3,728	1,750	$850.2	$826.1	-$24.2	-3%

Notes:

- Usage scenarios based on actual 2016-17 consumption data.
- Each tariff group contains NMIs that have data for the full period
- For customers with a primary and secondary tariff, consumption scenarios at the secondary tariff are independent from those at the primary tariff. Therefore, any combination of low, typical and high use scenarios between the primary and secondary tariff can be formed. For example a residential customer with a typical usage at the primary tariff may have a low energy usage at the secondary tariff.

Table 5-1 and Table 5-2 show that customers across the spectrum are expected to experience a decrease in their NUOS charges in 2018-19 compared with their 2017-18 charges. This is largely due to adjustments in demand and energy forecasts used for the development of the tariff levels, decreases in DUOS resulting from the 2016-17 over-recoveries returned to customers in 2018-19, and a 3.1 per cent decrease in DPPC (TUOS) charges. Further details on these changes between 2017-18 and 2018-19 are provided in Section 5.3 and Attachment 3.

Finally, it should be noted that the extent to which network signals actually seen by the majority of customers in our network is dependent on the Queensland Competition Authority's (QCA) determination on regulated retail prices for 2018-19. The QCA, under delegation from the Queensland Government, sets regulated retail prices based on its latest forecasts of providing electricity services. To calculate each regulated retail tariff (apart from historical transitional tariffs), the QCA uses a 'Network plus Retail' approach. The underlying network cost component may be based on our network tariffs and/or rates, or those of Energex.

Alternative Control Services

With respect to our Alternative Control Services, by their nature, most of these services are requested by customers, and can 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.

We also note that customers are able to limit price impacts by considering whether a different variant of the service may be preferable (e.g. customers may, in some circumstances, minimise the cost incurred for some services by choosing to have the service delivered during business hours rather than after hours). This, too, is consistent with economic efficiency principles.

As noted in our TSS the price cap control mechanism limits customer impacts by constraining annual price increases to a certain level. Furthermore, we expect that the AER's Distribution Determination takes customer impacts into account when establishing structures and prices consistent with the efficient operation and use of services for the long term interests of consumers.

On this basis, we believe adjustments to Alternative Control Services tariffs to satisfy clause 6.18.5(h) are not necessary.

5.1.2 Adjustments to tariffs to meet consumer impact principles and other regulatory instruments

Rule requirement

Clause 6.18.5 Application of the pricing principles

(c) A Distribution Network Service Provider's tariffs may vary from tariffs which would result from complying with the pricing principles set out in paragraphs (e) to (g) only:

(1) only to the extent permitted under paragraph (h); and

(2) to the extent necessary to give effect to the pricing principles set out in paragraphs (i) to (j).

Adjustments to Standard Control Services

As noted in Section 5.1.1 above, we have considered the impact on customers of changes to tariffs between regulatory years when setting our 2018-19 network tariffs in the following manner:

- Setting some tariffs at variance from the full LRMC values for both our legacy and optional tariffs (refer to Section 3.2.7)
- Selecting a combination of charges to recover Ergon Energy's 2018-19 residual revenue to support minimising distortion of the LRMC signal (refer to Section 3.2.8).

These measures are consistent with our TSS and clause 6.18.5(h) of the NER, and aim to smooth our transition to more cost reflective LRMC-based tariffs.

Clause 6.18.5(i) of the NER requires tariff structures to be reasonably capable of being understood by retail customers having regard to a number of factors. We have not made any adjustments to our tariffs in 2018-19 on the basis of this principle. Tariff structures are discussed in Section 2.2 of this Pricing Proposal.

Finally, clause 6.18.5(j) of the NER requires tariffs to comply with the NER and all applicable regulatory instruments. We confirm that our 2018-19 network tariffs have been developed to be compliant with the NER and the AER's Distribution Determination. We have demonstrated this through our approved TSS, this Pricing Proposal and associated attachments. A summary of our compliance with these obligations is set out in Appendix 2 of this Pricing Proposal.

Adjustments to Alternative Control Services

As noted in Section 5.1.1 above, we have not made any adjustment to Alternative Control Services tariffs to satisfy clause 6.18.5(h) of the NER.

However, as highlighted in Section 1.4.4, a number of our Alternative Control Services are impacted by Schedule 8 of the *Electricity Regulation 2006*. Consequently, we make further adjustments to the tariffs derived under the Pricing Proposal process to satisfy the maximum prices set out in Schedule 8. This means the prices customers will be actually charged in 2018-19 may be lower than the prices contained in Attachment 1. Once Schedule 8 is published for the 2018-19 regulatory year, we will update the rates for Alternative Control Services applicable for 2018-19, reflecting the Schedule 8 maximum price caps. These updated prices will be charged to customers in 2018-19.

5.2 Adjustments to tariffs within a regulatory year

Rule requirement

Clause 6.18.2 Pricing Proposals

(b) A *pricing proposal* must:

(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.

5.2.1 Adjustments to Standard Control Services tariff within 2018-19

Variations or adjustments to our network tariffs may occur where an ICC, CAC or EG customer advises us that they intend to alter their demand or connection characteristics during the course of the year. In these circumstances, we will recalculate the customer's charge with the adjustment to the charge occurring at the next network bill (noting that the published rates will continue to apply to CACs). New tariffs will be created for new ICCs and EGs that connect during 2018-19, in line with the methodology set out in this Pricing Proposal.

During 2018-19, we may also be required to calculate additional tariffs and/or prices for existing services which we have not provided prices for in this Pricing Proposal. This may occur because of a new customer connection in an area where the relevant tariff has not been established. For example, we may develop standardised rates for a customer who is seeking to connect to the Mount Isa network as a CAC.[28] We will seek approval from the AER to include a tariff and/or price at that time.

In circumstances where we are required to make a change to our TSS during a regulatory control period as a result of an event outside our control which could not reasonably have been foreseen, we may request from the AER the right to amend our TSS in accordance with clause 6.18.1B of the NER. If the AER is satisfied that the change to the TSS is warranted, we may be able to adjust the charge to the tariff in accordance with the revised TSS approved by the AER.

There are no other variations or adjustments proposed to be made to the Standard Control Services tariffs during the course of the regulatory year.

5.2.2 Alternative Control Service adjustments within 2018-19

With the exception of the application of Schedule 8 of the Electricity Regulation 2006 to a number of our Alternative Control Services as noted in Section 1.4.4 and of this Pricing Proposal, there are no variations or adjustments proposed to be made to Alternative Control Services tariffs during the course of the regulatory year.

5.3 Changes between regulatory years

Rule requirement

Clause 6.18.2 Pricing Proposals

(b) A *pricing proposal* must:

(8) describe the nature and extent of change from the previous *regulatory year* and demonstrate that the changes comply with the *Rules* and any applicable Distribution Determination.

28 Network tariffs for CACs in Mount Isa Zone are 'Price on application', as no CACs currently exist in this pricing zone.

This Pricing Proposal contains several changes since 2017-18. These changes are also largely reflected in our TSS.

5.3.1 Changes to the revenue requirement

This section outlines changes in the TAR between 2017-18 and 2018-19, including:

- Adjustment to the TAR components
- Jurisdictional schemes
- TUOS

A summary of the annual revenue adjustments is included in Table 5-3.

Table 5-3: Summary of annual revenue adjustments

Component	2017-18 values	2018-19 values	Reasons for change
CPI	1.48%	1.91%	Adjustment as per information published by the ABS – CPI All Groups, Average of Eight Capital Cities from the December quarter in 2016 to the December quarter in 2017.
X factor	(14.06%)	2.55%	X factor updated in PTRM
Capital contributions	n/a	n/a	No longer applicable since 2017-18
STPIS	$26.23 m	$26.13 m	The applicable S-factor for the year is 0.006%. It has been adjusted to reflect the previous year's S-factor.
DMIS carry-over	n/a	n/a	Not applicable since 2017-18.
DUOS under/over recover	($6.82) m	($45.97) m	DUOS over recovery in 2016-17 to be returned to customers in 2018-19
SBS FiT payments pass through for 2014-15		($2.46) m	Over-recovery in 2016-17 returned to customers
Jurisdictional schemes	$0	$0	Set to nil following the Queensland Government's direction not to pass through jurisdictional scheme amount.
TUOS	$264 m	$256 m	3% decrease in Powerlink charges between 2017-18 and 2018-19.

5.3.2 Network tariff changes for Standard Control Services

As noted in Section 1.5, we are proposing a number of changes to our network tariffs for Standard Control Services from 1 July 2018. The main change includes the introduction of an innovative residential time-of-use tariff, the Lifestyle tariff.

These change to our network tariffs are described in more detail in the remainder of this section and have been reflected in Attachment 1.

Changes to ICC network tariffs

Consistent with our TSS, no changes are proposed to ICC tariffs in 2018-19.

Changes to CAC network tariffs

Change in default tariff for CACs

As outlined in our 2017-18 Pricing Proposal and consistent with the approach foreshadowed in our TSS, since 1 March 2018 new CAC premise connections default to the STOUD where no network tariff has been advised to Ergon Energy. Customers wishing to opt-out of this arrangement can either request an initial assignment or re-assignment to one of our other standardised CAC tariffs. In 2018-19, we do not propose any further changes to CAC tariffs.

Changes to EG network tariffs

Standardised rates for EG tariffs

In our TSS, we foreshadowed that we would be considering introducing standardised rates for EG tariffs if the volume of new connections makes it impractical for us to continue site-specific pricing.

In 2018-19, we do not intend to introduce standardised rates for EGs. However, we will continue to monitor this during the year, and to the extent necessary, develop standardised rates for future Pricing Proposals.

Changes to SAC Large network tariffs

Change in default tariff for SAC Large

Consistent with the approach applied to CACs, from 1 March 2018, any new SAC Large premises connections default to the STOUD tariff where no network tariff has been advised to Ergon Energy. Customers wishing to opt out of this arrangement can either request an initial assignment or a re-assignment to the SAC Large anytime demand tariffs through their retailer. In 2018-19, we do not propose any further changes to SAC Large customers.

Change to residential tariffs

New Residential Lifestyle tariff

On 1 July 2018, we will offer a new residential tariff, Residential Lifestyle (Lifestyle Tariff) available to residential customers in the East Zone with smart meters and consumption less than 100 MWh per year. Access to this tariff is limited to a specified number of customers as the tariff is subject to the threshold tariff provisions set out in the NER.[29]

This tariff is an innovative and flexible product that has been developed with a view to providing customers choice in recognition of their lifestyle, technology and payment preferences. The Lifestyle Tariff is intended to deliver network objectives in a way that works for both the market and customers.

The main feature of the Lifestyle Tariff is to create a link between the cost of using the network and a customer's daily usage (expressed in kWh) of the network between 4pm and 9pm on any day in the summer season of November to March (the summer peak window). Customers can pay for their network usage during the summer peak window entirely on a pay as you use basis (choosing Band 1) or on a smoothed basis by paying a higher monthly charge (nominating Bands 2 to 5) that buys the right to access the network up to an agreed allocation of energy during the summer peak window. Should the customer's use of the

[29] NER, clause 6.18.1C(a).

network exceed the summer peak window allocation, a top-up charge will apply. There is no top-up charge for use of the network anytime outside of the summer peak window (April to October).

The customer's monthly charge comprises the following charging parameters: a fixed charge based on the usage band nominated by the customer, a top-up charge during the summer peak window (if triggered), and an energy usage charge.

The Lifestyle Tariff options are illustrated with examples of lifestyle preferences in Table 5-4 below.

Table 5-4: Lifestyle Tariff monthly bands

Network access allowance	Network use allowance in the band[a]	Examples of lifestyle options[b]
Access band 1	0 kWh – this band does not include any allowance for use of the network to transport electricity during the summer peak window.	Network used for back supply
Access band 2	Network access allowance up to 5kWh	Lean and green
Access band 3	Network access allowance up to 10 kWh	Modern and tech savvy
Access band 4	Network access allowance up to 15 kWh	Working family
Access band 5	Network access allowance up to 20 kWh	Risk averse

Notes:

a. This relates to the right to use the network to access up to an agreed allocation of energy during the summer peak window without incurring top-up charges.
b. The examples of lifestyle options set out in this table are for illustrative purposes only and not intended to be a means by which assignment to a band will occur.

This tariff structure offers enhanced choice and control to customers. Among other things, it has been designed to provide a tariff that is easier for customers to understand than a traditional time-of-use demand tariff and smooth out the impacts of summer bill peaks associated with recovering LRMC on a seasonal basis.

As demonstrated in Table 5-5 below, we consider that the new Lifestyle Tariff aligns with pricing principles set out in NER. The tariff structure is fundamentally a seasonal, time-of-use tariff that recovers the LRMC during the summer peak window. The tariff provides clear benefits to customers if they choose to reduce usage during the summer peak window and introduces new choice and control options for the customer.

Table 5-5 Alignment with pricing principles

Pricing principles	Alignment
Cost reflectivity	The Lifestyle Tariff has been designed to address cross subsidies by reflecting the true cost of using the network. It also encourages more efficient use of the network.
Tariff must be based on LRMC	This principle is met by incorporating 100 per cent LRMC in the band and top up charging parameters of the tariff. Both of these incorporate charges relating to customer use of the network during the summer peak window.
Customer impact	The tariff is offered only to volunteering customers who agree to participate to a tariff trial.

Noting that the Lifestyle Tariff is a departure from our current 2017-20 TSS, we are seeking the AER's approval to invoke clause 6.18.1C of the NER which permits a DNSP to introduce a new tariff that is not included in its TSS so long as the following conditions are met:

- The AER, the affected retailers and affected retail customers have been notified no later than four months before the start of the regulatory year – This condition is met by:
  - informing the AER through on-going discussions during the course of 2017 of our intention to offer a new innovative tariff to a limited number of residential customers
  - including the new proposed Lifestyle Tariff in this Pricing Proposal
  - seeking the introduction of the new voluntary Lifestyle Tariff to be gazetted and included in the notified prices for regional Queensland in February 2018. As part of the Queensland Competition Authority's engagement process, we are of the view that retailers and customers have been informed of our intention to offer the new tariff from 1 July 2018[30]
  - updating our website.
- The forecast revenue from the relevant tariff during each regulatory year in which the tariff is to apply is no greater than 0.5 per cent of our annual revenue requirement for that regulatory year (the individual threshold) – This condition is met by limiting the maximum number of customers being able to take up the Lifestyle tariff to 4000 customers[31], to ensure that the expected revenue to be recovered from that tariff will remain below the allowable threshold of $6.4 m; and
- Our forecast revenue from the relevant tariff, as well as from all other relevant tariffs, during each regulatory year in which those tariffs are to apply is no greater than one per cent of our annual revenue requirement for that regulatory year (the cumulative threshold) – This obligation is not relevant as there are no other relevant tariffs that would invoke the use of the cumulative threshold.

The tariff structure and terms and conditions are set out in Appendix 1, and the proposed tariff levels are included in Attachment 1.

5.3.3 Alternative Control Services changes

We have made a number of amendments to our Alternative Control Services since 2017–18.

The first difference between 2017-18 and 2018-19 relates to the CPI values being updated from 1.48 per cent to 1.91 per cent, resulting in a slight increase.

The second change relates to Power of Choice taking effect on 1 December 2017. As a result, we amended a number of Alternative Control Services to separate the metering service component with the remaining service components covering the services still performed by Ergon Energy. The changes included:

- Certain services needed to be restructured and disaggregated into various charging components to reflect the possible permutations introduced by metering service contestability
- Certain services, such as meter installations, were discontinued
- Certain services had to be duplicated to allow charging to either the customer or metering co-ordinator.

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30 It should also be noted that, following stakeholder engagement in February 2018, the Queensland Competition Authority, in its Draft Determination, endorsed the trial of the proposed tariff (T15). Refer Queensland Competition Authority's Draft Determination on Regulated Retail Electricity Prices for 2018-19, February 2018.

31 Conservative estimate based on the assumptions that all customers who agreed to participate to the trial have chosen Band 5 (the most expensive option) and are in transmission Region 3.

The abovementioned amendments and associated revised prices were approved by the AER in December 2017.

Further information on the impact of Power of Choice on our Alternative Control Services can be found on our website.

5.4 Differences between the proposed 2018-19 prices and relevant indicative prices

Rule requirement

Clause 6.18.2 Pricing Proposals

(b) A *pricing proposal* must:

(7A) demonstrate how each proposed tariff is consistent with the corresponding indicative pricing levels for the relevant *regulatory year* as set out in the relevant *indicative pricing schedule*, or explain any material differences between them.

We note that the NER obligation only requires us to provide (and explain material differences) for our Direct Control Services (i.e. Standard Control Services (DUOS) and Alternative Control Services). While our 2018-19 indicative pricing schedule provides indicative prices for TUOS charges too, we have focused our explanation on the differences in our DUOS and Alternative Control Services prices.

5.4.1 Differences in Standard Control Services pricing levels

To satisfy clause 6.18.2(b)(7A) of the NER, we have included a comparison between the indicative 2018-19 rates set out in the 2017-18 Indicative Pricing Schedule submitted as part of the 2017-18 Pricing Proposal, and the proposed 2018-19 rates submitted as part of this Pricing Proposal, in the (confidential) Tariff Approval Model and Attachment 3. The differences are expressed as both absolute values and as weighted percentages to provide an indication of the significance of the change relative to the overall tariff revenue recovery.

Overall, the proposed 2018-19 rates are in line with the indicative rates, but as would be anticipated there is variability in the change occurring between the individual rates.

The calculation of individual rates is impacted by a number of inputs which have been updated between the preparation of the indicative rates for the 2017-18 Indicative Pricing Schedule and this Pricing Proposal. Key inputs impacting rate calculation include:

- the final TAR (refer Section 3.2.1)
- TUOS and Jurisdictional Scheme outcomes (refer to Sections 3.3 and 3.4)
- updating of customer number, energy and demand forecasts which underpin the prices (refer Section 3.4.2)
- updating of customer profile data used in our tariff models.[32] Tariff rate outcomes can be quite sensitive to changes in these inputs, particularly in the case of relatively small customer and revenue allocations to a tariff class.

As noted in Section 3.2.7, consistent with our TSS and clause 6.18.5(h) of the NER, Ergon Energy is progressively increasing the appropriate voltage-level LRMC to the peak charging component of each

[32] Ergon Energy uses a co-optimisation model to simultaneously calculate all the tariffs available to a single tariff class.

customer class, in all pricing zones. The concentration of the impact of variation in the residual components means individual charging parameters can show a larger variation than the impact if looked at with reference to all the charging parameters in the tariff. In recognition of this, in Attachment 3 we have also calculated the difference weighted by the proportion of the total tariff revenue recovered by the charging parameter.

Overall NUOS revenue is down 4 per cent ($58.52 m), DUOS revenue is down 4 per cent ($50.82 m), while our forecast customer numbers and energy consumption has been refined based on latest historical data available.

When looking at the price level comparisons provided, a degree of caution should be exercised as tariffs are to be considered as more than the sum of individual parameters and associated rates. Indeed, the rates of the charging parameters ‘contribute’ in varying amount to the overall NUOS revenue recovery at the overall tariff level. That is, each charging parameter within a tariff has a weighting (or percentage) of the overall NUOS revenue recovery. This means that a large percentage change on a specific charge parameter that only has a small weighting of overall NUOS revenue recovery will have a smaller impact on the overall cost outcome of the tariff than the increase on the single charge parameter would indicate.

With respect to materiality we have referenced a difference of over 15 per cent in an individual rate as the threshold to explain the difference. As inferred above, our tariffs typically have more than one charging parameter, each with an associated rate. Generally even where a single rate has changed by 15 per cent more than the indicative rates, it may also be offset by variations in other charging parameters in that tariff.

A further description of material changes by customer class, for each type of charge relating to our Standard Control Services is set out below.

DUOS rate changes

Material SAC Small rate changes

Ergon Energy’s proposed 2018-19 SAC Small East and Mount Isa Block 3 rates are higher than the indicative rates provided in the 2017-18 indicative pricing schedule due to forecast volumes being lower at the time of setting the proposed rates than those used for last year’s revised indicative prices. In accordance with our approach which predetermines the fixed and Block 1 charges, the variability is pushed into Block 2 and 3. Furthermore, due to relatively less energy consumed in Block 3, the impact on the rate is higher to recover the residual revenue.

Ergon Enery’s proposed 2018-19 SAC Small Mount Isa Unmetered volume rate is lower than the revised indicative schedule. The 2018-19 proposed rate is in line with the projected suite of rates and the rate proposed in the revised indicative schedule was an oversighted increase corrected before being applied to customers.

Material SAC Large Rate Changes

Ergon Energy’s proposed 2018-19 SAC Large volume rates are lower than the revised indicative schedule. This is due to:

- forecast volumes being lower than those used for the indicative prices, and
- alignment of volume rates across Demand Large, Demand Medium and Demand Small.

Material CAC Rate Changes

Ergon Energy’s proposed 2018-19 CAC 66kV West actual demand charge is lower than the revised indicative schedule. Due to the small number of customers on this tariff, rates are highly sensitive to changes in forecast quantities. In this case, an increase in forecast demand has resulted in a significant reduction in the rate.

Ergon Energy's proposed 2018-19 CAC West volume rates are lower than the revised indicative schedule. Due to the relatively small quantities in revenue and forecast energy, rates are more sensitive to changes in revenue and energy consumed.

TUOS rate changes

The modest reduction in the proposed 2018-19 TUOS rates from the indicatives is attributable to a change in forecast customer data and final Powerlink revenue.

It is noted that the variation between the indicative and proposed 2018-19 TUOS rates is not uniform between the transmission regions. This is attributable to the regions reflecting the specific costs that Powerlink charges for the services provided in each of the regions and this changes to reflect the outcomes of Powerlink's allocation methodology. Rates will also change as customer numbers, energy and demand change within each of the individual regions. These inputs are updated independently which then flows through to differences in relative movements in each of the regions.

Jurisdictional Scheme rate changes

As per last year, jurisdictional scheme has not been included this year in our rates as per the Government's direction.

5.4.2 Differences in Alternative Control Service pricing levels

The price cap control mechanism that applies to our Alternative Control Services constrains movements in prices to a certain level. Any differences between our indicative 2018-19 prices set out in our 2017-18 Indicative Pricing Schedule and the proposed prices in this Pricing Proposal, are directly attributable to allowable changes to annual cost inputs (e.g. overheads and oncosts – see Section 4.4), or as applied in the control mechanism formulae itself (e.g. adjustment to the CPI from 1.48 per cent to 1.91 per cent).

As noted in Section 5.3.3, with Power of Choice taking effect on 1 December 2017, a number of Alternative Control Services experienced lower charges as a result of the metering service component being removed.

With the exception of the services impacted by Power of Choice, we confirm that our Alternative Control Services prices are consistent with those presented in our 2017-18 Indicative Pricing Schedule, and that there are no material differences between our indicative and proposed 2018-19 prices.

5.5 Updated indicative pricing levels

Rule requirement

Clause 6.18.2 Pricing proposals

(d) At the same time as a *Distribution Network Service Provider* submits a pricing proposal under paragraph (a), the *Distribution Network Service Provider* must submit to the AER a revised indicative pricing schedule which sets out, for each tariff and for each of the remaining regulatory years of the regulatory control period, the indicative price levels determined in accordance with the *Distribution Network Service Provider's* tariff structure statement and updated so as to take into account that pricing proposal.

Attachment 2 sets out our latest estimates of indicative prices for the remaining year of the current regulatory control period (2019-20) for both our Standard and Alternative Control Services. These prices are based on tariff structures detailed in our TSS and current expectations regarding annual pricing inputs.

Prices for our fee based services (capped price), Default Metering Services and Public Lighting Services will be escalated in accordance with the price cap formulae approved by the AER in the Distribution Determination. This annual escalation process typically involves applying:

- the X factor specified in the Distribution Determination (incorporated in the indicative prices)
- a CPI adjustment (to be updated each year).

For quoted services, prices will vary depending on the actual requirements of the service being requested. Prices are expected to change as a result of the following adjustments:

- the difference between forecast and actual inflation
- changes to underlying real costs (refer to Section 4.4 above).

The underlying assumptions we have applied for each type of charge relating to our Standard Control Services is set out in Table 5-6 below.

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

Other charges that do not relate to the costs of using our network (i.e. TUOS) may also affect future price trends.

Table 5-6: Assumptions underpinning the expected price trends for Standard Control Services

Type of charge	Assumptions applied
DUOS	• Applied the revenues from the Distribution Determination, with no adjustments for the s-factor,[33] inflation or the return on debt. In practice, the AER is likely to approve adjustments for these factors, in accordance with the revenue cap formula. • Included a forecast DUOS over recovery adjustment in 2018-19, noting the final position is not yet known. No adjustments have been applied in future years. • Used high level assumptions regarding: o energy and demand o customer numbers o customer churn. These forecasts are consistent with approach outlined in Section 3.5 and will be updated each year, once actual outcomes from prior years are known.
TUOS	• Forecast expense amounts for Powerlink charges were based on discussions with Powerlink. • For Avoided TUOS and inter-distributor payments, we used forecast energy quantities and forecast charge rate.[34] • Included a forecast TUOS over recovery adjustment in 2018-19, noting the final position is not yet known. No adjustments have been applied in future years.

33 Except 2018-19. We have applied an estimated s-factor.

34 For Chumvale, we apply 50 per cent of the applicable CPI increase.

5.6 Publication of information

Rule requirement

Clause 6.18.2 Publication of information about tariffs and tariff classes

(a) A Distribution Network Service Provider must maintain on its website:

(2) its current indicative pricing schedule

(3) a statement of the provider's tariff classes and tariffs applicable to each class.

Clause 6.18.9 of the NER requires Ergon Energy to publish, and maintain a range of information about our tariffs on our website, including:

- our current indicative pricing schedule
- a statement of our tariff classes and tariffs applicable to each class.

The NER also prescribes timeframes, in which Ergon Energy must publish this information.[35]

Our 2018-19 Pricing Proposal and associated attachments (including our revised indicative pricing schedule) will be made available on Ergon Energy's website as soon as practical, and in any case, no later than 5 business days following AER approval.

[35] NER, clauses 6.18.9(a1) and (b).

Appendix 1: Proposed tariffs and charging parameters

Consistent with our TSS, this appendix sets out our proposed tariffs for our distribution services for 2018-19. It should be noted that our proposed 2018-19 charges for Standard and Alternative Control Services are provided in a separate document, Attachment 1 – Ergon Energy 2018-19 Network Charges, which accompanies this Pricing Proposal.

Table A1.2: Standard Control Services tariffs and tariff structures for primary tariffs for 2018-19

Tariff	Charging parameter	Units
SAC Small default tariffs		
IBT Residential		
IBT Residential East (ERIB)	Fixed	$/day
	Volume Block 1	$/kWh
	Volume Block 2	$/kWh
	Volume Block 3	$/kWh
IBT Residential West (WRIB)	Fixed	$/day
	Volume Block 1	$/kWh
	Volume Block 2	$/kWh
	Volume Block 3	$/kWh
IBT Residential Mount Isa (MRIB)	Fixed	$/day
	Volume Block 1	$/kWh
	Volume Block 2	$/kWh
	Volume Block 3	$/kWh
IBT Business		
IBT Business East (EBIB)	Fixed	$/day
	Volume Block 1	$/kWh
	Volume Block 2	$/kWh
	Volume Block 3	$/kWh
IBT Business West (WBIB)	Fixed	$/day
	Volume Block 1	$/kWh
	Volume Block 2	$/kWh
	Volume Block 3	$/kWh
IBT Business Mount Isa (MBIB)	Fixed	$/day
	Volume Block 1	$/kWh
	Volume Block 2	$/kWh
	Volume Block 3	$/kWh
SAC Small optional tariffs		
Seasonal TOU Energy Residential		
Seasonal TOU Energy Residential East (ERTOU)	Fixed	$/day
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
Seasonal TOU Energy Residential West	Fixed	$/day
	Volume Peak	$/kWh

(WRTOU)	Volume Off Peak	$/kWh
Seasonal TOU Energy Residential Mount Isa (MRTOU)	Fixed	$/day
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
Seasonal TOU Energy Business		
Seasonal TOU Energy Business East (EBTOU)	Fixed	$/day
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
Seasonal TOU Energy Business West (WBTOU)	Fixed	$/day
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
Seasonal TOU Energy Business Mount Isa (MBTOU)	Fixed	$/day
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
Seasonal TOU Demand Residential		
Seasonal TOU Demand Residential East (ERTOUD)	Fixed	$/day
	Actual Demand Peak	$/kW/mth
	Actual Demand Off Peak	$/kW/mth
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
Seasonal TOU Demand Residential West (WRTOUD)	Fixed	$/day
	Actual Demand Peak	$/kW/mth
	Actual Demand Off Peak	$/kW/mth
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
Seasonal TOU Demand Residential Mount Isa (MRTOUD)	Fixed	$/day
	Actual Demand Peak	$/kW/mth
	Actual Demand Off Peak	$/kW/mth
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
Seasonal TOU Demand Business		
Seasonal TOU Demand Business East (EBTOUD)	Fixed	$/day
	Actual Demand Peak	$/kW/mth
	Actual Demand Off Peak	$/kW/mth
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
Seasonal TOU Demand Business West (WBTOUD)	Fixed	$/day
	Actual Demand Peak	$/kW/mth
	Actual Demand Off Peak	$/kW/mth
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
Seasonal TOU Demand Business Mount Isa (MBTOUD)	Fixed	$/day
	Actual Demand Peak	$/kW/mth
	Actual Demand Off Peak	$/kW/mth

	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
Residential Lifestyle Tariff		
Residential Lifestyle Tariff (ERL)	Access band 1	$/month
	Access band 2	$/month
	Access band 3	$/month
	Access band 4	$/month
	Access band 5	$/month
	Summer Peak Top-up	$/kWh
	Volume	$/kWh
SAC Small secondary tariffs		
Controlled load		
Volume Night Controlled East (EVN)	Fixed	$/day
	Volume	$/kWh
Volume Night Controlled West (WVN)	Fixed	$/day
	Volume	$/kWh
Volume Night Controlled Mount Isa (MVN)	Fixed	$/day
	Volume	$/kWh
Volume Controlled East (EVC)	Fixed	$/day
	Volume	$/kWh
Volume Controlled West (WVC)	Fixed	$/day
	Volume	$/kWh
Volume Controlled Mount Isa (MVC)	Fixed	$/day
	Volume	$/kWh
Unmetered supply		
Unmetered supply		
Unmetered Supply East (EVU, EVUMI, EVUMA)	Fixed	$/day
	Volume	$/kWh
Unmetered Supply West (WVU, WVUMI, WVUMA)	Fixed	$/day
	Volume	$/kWh
Unmetered Supply Mount Isa (MVU, MVUMI, MVUMA)	Fixed	$/day
	Volume	$/kWh

Notes:

Application of tariff and charges	
SAC Small default tariffs	
IBT tariffs - Residential and Business	
Volume charge	The volume charge is charged according to three blocks. The inclining blocks are triggered once a customer exceeds each nominated consumption threshold. 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.
Residential - consumption	

<table>
<tr><th colspan="2">Application of tariff and charges</th></tr>
<tr><td>blocks</td><td>
<table>
<tr><th>Block</th><th>Daily kWh</th><th>Annual equivalent kWh</th></tr>
<tr><td>Block 1</td><td><2.74 kWh</td><td><1,000 kWh per annum</td></tr>
<tr><td>Block 2</td><td>2.74 - 16.43 kWh</td><td>1,000 - 6,000 kWh per annum</td></tr>
<tr><td>Block 3</td><td>>16.43 kWh</td><td>>6,000 kWh per annum</td></tr>
</table>
</td></tr>
<tr><td>Business – consumption blocks</td><td>
<table>
<tr><th>Block</th><th>Daily kWh</th><th>Annual equivalent kWh</th></tr>
<tr><td>Block 1</td><td><2.74 kWh</td><td><1,000 kWh per annum</td></tr>
<tr><td>Block 2</td><td>2.74 - 54.76 kWh</td><td>1,000 - 20,000 kWh per annum</td></tr>
<tr><td>Block 3</td><td>>54.76 kWh</td><td>>20,000 kWh per annum</td></tr>
</table>
</td></tr>
<tr><th colspan="2">SAC Small optional tariffs</th></tr>
<tr><th colspan="2">Seasonal TOU Energy tariffs – Residential and Business</th></tr>
<tr><td>Opt-in arrangements</td><td>A customer (or their retailer) must request a tariff change to opt in to these tariffs. Tariff access considerations include suitable metering.</td></tr>
<tr><td>Residential – time periods</td><td>
<table>
<tr><td>Peak</td><td>3:00pm to 9:30pm on all summer days</td></tr>
<tr><td>Off-Peak</td><td>All other times</td></tr>
</table>
Note: ‘Summer’ is defined as the months of December, January and February</td></tr>
<tr><td>Business – time periods</td><td>
<table>
<tr><td>Peak</td><td>10:00am to 8:00pm on summer weekdays</td></tr>
<tr><td>Off-Peak</td><td>All other times</td></tr>
</table>
Note: ‘Summer’ is defined as the months of December, January and February</td></tr>
<tr><th colspan="2">Seasonal TOU Demand tariffs – Residential and Business</th></tr>
<tr><td>Opt-in arrangements</td><td>A customer (or their retailer) must request a tariff change to opt in to these tariffs. Tariff access considerations include suitable metering.</td></tr>
<tr><td>Residential – time periods</td><td>
<table>
<tr><td>Peak demand</td><td>3:00pm to 9:30pm all summer days</td></tr>
<tr><td>Off-Peak demand</td><td>3:00pm to 9:30pm all non-summer days</td></tr>
<tr><td>Energy</td><td>An any time energy (volume) charge applies to all metered consumption</td></tr>
</table>
</td></tr>
</table>

<table>
<tr><th colspan="2">Application of tariff and charges</th></tr>
<tr><td></td><td>Note: ‘Summer’ is defined as the months of December, January and February</td></tr>
<tr><td>Business – time periods</td><td><table><tr><td>Peak demand</td><td>10:00am to 8:00pm on summer weekdays</td></tr><tr><td>Off-Peak demand</td><td>10:00am to 8:00pm on non-summer weekdays</td></tr><tr><td>Energy</td><td>An any time energy (volume) charge applies to all metered consumption</td></tr></table>Note: ‘Summer’ is defined as the months of December, January and February</td></tr>
<tr><td>Chargeable demand quantities</td><td>Determination of the chargeable demand quantity is the same for both the peak and off-peak demand charges (Note: A minimum chargeable demand of 3 kW applies in non-summer months)</td></tr>
<tr><td>Demand charges</td><td>The monthly demand charges, for both summer and non-summer, are based on the average demand the customer places on the network in the daily demand window
Residential the 6.5 hour peak period between 3:00pm and 9:30pm
Business the 10 hour peak period on weekdays between 10:00am and 8:00pm
The highest four demand days in the month are determined by comparison of the average demand recorded in these daily demand windows. The monthly demand rate is applied to the average of these top four demand days.
In the non-summer months a minimum chargeable demand of 3 kW also applies – meaning the customer pays for 3 kW of demand or the average of their top four average demand days in the month, whichever is the greater.</td></tr>
<tr><td>Volume charges</td><td>The volume calculation is based on a $/kWh rate applied to all metered kWh consumption for the billing period (both peak and off-peak).</td></tr>
<tr><th colspan="2">Residential Lifestyle Tariff – Residential tariff for residential customers in the East zone with consumption less than 100MWh per year</th></tr>
<tr><td>Network Access Allowance</td><td>Monthly charge based on the customer’s nominated band. The bands are set out below:<table><tr><th>Network access allowance</th><th>Summer peak window network use allowance in the band</th></tr><tr><td>Access band 1</td><td>0 kWh</td></tr><tr><td>Access band 2</td><td>Up to 5 kWh</td></tr><tr><td>Access band 3</td><td>Up to 10 kWh</td></tr><tr><td>Access band 4</td><td>Up to 15 kWh</td></tr><tr><td>Access band 5</td><td>Up to 20 kWh</td></tr></table></td></tr>
</table>

Application of tariff and charges	
	Customers can choose the band option that matches their maximum use in the summer peak window and payment preferences.
Summer peak top-up charge	The summer peak top-up charge is applied to the single maximum daily energy consumed above the threshold associated with the nominated band during the billing period. The summer peak top-up charge applies to network use during the summer peak window which is defined as: November to March, any day between 4pm and 9pm. The summer peak top-up rate is the same regardless of the chosen band. There is no top up charge for exceeding the agreed allowance anytime outside of the summer peak window. Once the allocation is exceeded, the increased amount remains available for the rest of the month and then resets back to the original nominated allowance at the start of the month.
Volume charge	The volume calculation is based on a $/kWh charge applied to all metered kWh consumption for the billing period (both during and outside the summer peak window). The volume rate is the same regardless of the chosen band. The anytime volume charge applies to all energy supplied from the grid.
Further conditions	The tariff is designed to operate with a smart meter. Once choice of access band is made, customers cannot choose a lower band until they have been on the chosen band for a full 12 months. Customers, however, can choose to move to increase their network access allowance by moving to a higher band at any time.

Table A1.2: SAC Large DUoS prices

Tariff	Charging parameter	Units
SAC Large default tariffs		
Demand Large		
Demand Large East (EDLT)	Fixed	$/day
	Actual Demand	$/kW/mth
	Volume	$/kWh
Demand Large West (WDLT)	Fixed	$/day
	Actual Demand	$/kW/mth
	Volume	$/kWh
Demand Large Mount Isa (MDLT)	Fixed	$/day
	Actual Demand	$/kW/mth
	Volume	$/kWh
Demand Medium		
Demand Medium East (EDMT)	Fixed	$/day
	Actual Demand	$/kW/mth
	Volume	$/kWh
Demand Medium West (WDMT)	Fixed	$/day
	Actual Demand	$/kW/mth
	Volume	$/kWh
Demand Medium Mount Isa (MDMT)	Fixed	$/day
	Actual Demand	$/kW/mth
	Volume	$/kWh
Demand Small		
Demand Small East (EDST)	Fixed	$/day
	Actual Demand	$/kW/mth
	Volume	$/kWh
Demand Small West (WDST)	Fixed	$/day
	Actual Demand	$/kW/mth
	Volume	$/kWh
Demand Small Mount Isa (MDST)	Fixed	$/day
	Actual Demand	$/kW/mth
	Volume	$/kWh
SAC-Large optional tariffs		
Seasonal TOU Demand		
Seasonal TOU Demand East (ESTOUDC)	Fixed	$/day
	Actual Demand Peak	$/kW/mth
	Actual Demand Off Peak	$/kW/mth
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
Seasonal TOU Demand West (WSTOUDC)	Fixed	$/day
	Actual Demand Peak	$/kW/mth
	Actual Demand Off Peak	$/kW/mth

Tariff	Charging parameter	Units
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
Seasonal TOU Demand Mount Isa (MSTOUDC)	Fixed	$/day
	Actual Demand Peak	$/kW/mth
	Actual Demand Off Peak	$/kW/mth
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh

Notes:

<table>
<tr><th colspan="2">Application of tariff and charges</th></tr>
<tr><td colspan="2">SAC Large default tariffs</td></tr>
<tr><td colspan="2">Demand Large, Demand Medium, Demand Small</td></tr>
<tr><td>Actual demand charge</td><td>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. Where the monthly metered maximum demand is less than the demand threshold, the chargeable demand for that month is set to zero and no demand charge is payable for that month. The same demand threshold calculation mechanism is applied for TUOS charges.</td></tr>
<tr><td>Threshold above which demand charge applies</td><td><table><tr><td>Demand Large</td><td>400kW</td></tr><tr><td>Demand Medium</td><td>120kW</td></tr><tr><td>Demand Small</td><td>30kW</td></tr></table>Note: applies for DUoS and TUOS charges</td></tr>
<tr><td colspan="2">SAC Large optional tariffs</td></tr>
<tr><td colspan="2">Seasonal TOU Demand</td></tr>
<tr><td>Opt-in (and opt-out) arrangements</td><td>Generally a customer (or their retailer) must request a tariff change to opt in to these tariffs. Tariff access considerations include suitable metering. From 1 March 2018, any new SAC Large premise connections will default to the STOUD where no network tariff has been advised to Ergon Energy.</td></tr>
<tr><td>Time periods</td><td>.<table><tr><td>Peak demand</td><td>10:00am to 8:00pm on summer weekdays</td></tr><tr><td>Off-Peak demand</td><td>All times during non-summer months</td></tr><tr><td>Peak energy</td><td>All times during summer months</td></tr><tr><td>Off-peak energy</td><td>All times during non-summer months</td></tr></table>Note: 'Summer' is defined as the months of December, January and February.</td></tr>
<tr><td>Demand calculation (peak)</td><td>The peak demand calculation uses the highest kW maximum demand in any single half hour at any time during the peak demand period in each summer month (any single half hour between 10:00am and 8:00pm on a summer weekday). The demand charge will be applied to the kW amount by which a customer's actual monthly maximum demand is</td></tr>
</table>

Application of tariff and charges	
	greater than the demand threshold applicable to the peak period. Where the monthly metered maximum demand is less than the demand threshold, the chargeable demand for that month is set to zero
Demand calculation (off-peak)	The off-peak demand calculation uses the highest kW maximum demand in any single half hour at any time during the peak demand period in each non-summer month. The 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 off-peak period. Where the monthly metered maximum demand is less than the demand threshold, the chargeable demand for that month is set to zero
Threshold above which demand charge applies	Peak: 20kW Off-peak: 40kW Note: Applies to DUoS and TUOS charges.
Volume calculation (peak)	The peak volume calculation is based on a $/kWh rate applied to metered kWh consumption at all times during summer months. In 2018-19, the DUoS peak energy rate is set to $0/kWh.
Volume calculation (off-peak)	Volume calculation (off-peak) - The off-peak volume calculation is based on a $/kWh rate applied to metered kWh consumption at all times during non-summer months.

Table A1.3: CAC DUoS prices

Tariff	Charging parameter	Units	
CAC default tariffs			
CAC 66 kV			
CAC 66 kV East (EC66)	Fixed	$/day	
	Connection Unit	$/day/connection unit	
	Capacity	$/kVA/mth of AD	
	Actual Demand	$/kVA/mth	
	Volume	$/kWh	
	Excess Reactive Power	$/excess kVAr	
CAC 66 kV West (WC66)	Fixed	$/day	
	Connection Unit	$/day/connection unit	
	Capacity	$/kVA of AD/mth	
	Actual Demand	$/kVA/mth	
	Volume	$/kWh	
	Excess Reactive Power	$/excess kVAr	
CAC 66 kV Mount Isa (MC66)	Fixed	$/day	
	Connection Unit	$/day/connection unit	
	Capacity	$/kVA of AD/mth	
	Actual Demand	$/kVA/mth	
	Volume	$/kWh	
	Excess Reactive Power	$/excess kVAr	
CAC 33 kV			
CAC 33 kV East (EC33)	Fixed	$/day	
	Connection Unit	$/day/connection unit	
	Capacity	$/kVA of AD/mth	
	Actual Demand	$/kVA/mth	
	Volume	$/kWh	
	Excess Reactive Power	$/excess kVAr	
CAC 33 kV West (WC33)	Fixed	$/day	
	Connection Unit	$/day/connection unit	
	Capacity	$/kVA of AD/mth	
	Actual Demand	$/kVA/mth	
	Volume	$/kWh	
	Excess Reactive Power	$/excess kVAr	
CAC 33 kV Mount Isa (MC33)	Fixed	$/day	
	Connection Unit	$/day/connection unit	
	Capacity	$/kVA of AD/mth	
	Actual Demand	$/kVA/mth	
	Volume	$/kWh	
	Excess Reactive Power	$/excess kVAr	

Tariff	Charging parameter	Units
CAC 22/11 kV Bus		
CAC 22/11 kV Bus East (EC22B)	Fixed	$/day
	Connection Unit	$/day/connection unit
	Capacity	$/kVA of AD/mth
	Actual Demand	$/kVA/mth
	Volume	$/kWh
	Excess Reactive Power	$/excess kVAr
CAC 22/11 kV Bus West (WC22B)	Fixed	$/day
	Connection Unit	$/day/connection unit
	Capacity	$/kVA of AD/mth
	Actual Demand	$/kVA/mth
	Volume	$/kWh
	Excess Reactive Power	$/excess kVAr
CAC 22/11 kV Bus Mount Isa (MC22B)	Fixed	$/day
	Connection Unit	$/day/connection unit
	Capacity	$/kVA of AD/mth
	Actual Demand	$/kVA/mth
	Volume	$/kWh
	Excess Reactive Power	$/excess kVAr
CAC 22/11 kV Line		
CAC 22/11 kV Line East (EC22L)	Fixed	$/day
	Connection Unit	$/day/connection unit
	Capacity	$/kVA of AD/mth
	Actual Demand	$/kVA/mth
	Volume	$/kWh
	Excess Reactive Power	$/excess kVAr
CAC 22/11 kV Line West (WC22L)	Fixed	$/day
	Connection Unit	$/day/connection unit
	Capacity	$/kVA of AD/mth
	Actual Demand	$/kVA/mth
	Volume	$/kWh
	Excess Reactive Power	$/excess kVAr
CAC 22/11 kV Line Mount Isa (MC22L)	Fixed	$/day
	Connection Unit	$/day/connection unit
	Capacity	$/kVA of AD/mth
	Actual Demand	$/kVA/mth
	Volume	$/kWh
	Excess Reactive Power	$/excess kVAr
CAC optional tariffs		
Seasonal TOU Demand Higher Voltage		
Seasonal TOU Demand CAC Higher Voltage East	Fixed	$/day
	Connection Unit	$/day/connection unit

Tariff	Charging parameter	Units
(66/33 kV) (EC66TOU)	Actual Demand Peak	$/kVA/month
	Capacity Off Peak	$/kVA/mth of AD
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
	Excess Reactive Power	$/excess kVAr
Seasonal TOU Demand CAC Higher Voltage West (66/33 kV) (WC66TOU)	Fixed	$/day
	Connection Unit	$/day/connection unit
	Actual Demand Peak	$/kVA/month
	Capacity Off Peak	$/kVA/mth of AD
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
	Excess Reactive Power	$/excess kVAr
Seasonal TOU Demand CAC Higher Voltage Mount Isa (66/33 kV) (MC66TOU)	Fixed	$/day
	Connection Unit	$/day/connection unit
	Actual Demand Peak	$/kVA/month
	Capacity Off Peak	$/kVA/mth of AD
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
	Excess Reactive Power	$/excess kVAr
Seasonal TOU Demand CAC 22/11 kV Bus		
Seasonal TOU Demand CAC 22/11 kV Bus East (EC22BTOU)	Fixed	$/day
	Connection Unit	$/day/connection unit
	Actual Demand Peak	$/kVA/month
	Capacity Off Peak	$/kVA/mth of AD
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
	Excess Reactive Power	$/excess kVAr
Seasonal TOU Demand CAC 22/11 kV Bus West (WC22BTOU)	Fixed	$/day
	Connection Unit	$/day/connection unit
	Actual Demand Peak	$/kVA/month
	Capacity Off Peak	$/kVA/mth of AD
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
	Excess Reactive Power	$/excess kVAr
Seasonal TOU Demand CAC 22/11 kV Bus Mount Isa (MC22BTOU)	Fixed	$/day
	Connection Unit	$/day/connection unit
	Actual Demand Peak	$/kVA/month
	Capacity Off Peak	$/kVA/mth of AD
	Volume Peak	$/kWh
	Volume Off Peak	$/kWh
	Excess Reactive Power	$/excess kVAr

Tariff	Charging parameter	Units	
Seasonal TOU Demand CAC 22/11 kV Line			
Seasonal TOU Demand CAC 22/11 kV Line East (EC22LTOU)	Fixed	$/day	
	Connection Unit	$/day/connection unit	
	Actual Demand Peak	$/kVA/month	
	Capacity Off Peak	$/kVA/mth of AD	
	Volume Peak	$/kWh	
	Volume Off Peak	$/kWh	
	Excess Reactive Power	$/excess kVAr	
Seasonal TOU Demand CAC 22/11 kV Line West (WC22LTOU)	Fixed	$/day	
	Connection Unit	$/day/connection unit	
	Actual Demand Peak	$/kVA/month	
	Capacity Off Peak	$/kVA/mth of AD	
	Volume Peak	$/kWh	
	Volume Off Peak	$/kWh	
	Excess Reactive Power	$/excess kVAr	
Seasonal TOU Demand CAC 22/11 kV Line Mount Isa (MC22LTOU)	Fixed	$/day	
	Connection Unit	$/day/connection unit	
	Actual Demand Peak	$/kVA/month	
	Capacity Off Peak	$/kVA/mth of AD	
	Volume Peak	$/kWh	
	Volume Off Peak	$/kWh	
	Excess Reactive Power	$/excess kVAr	

Notes:

Application of tariff and charges	
CAC default tariffs	
CAC 66 kV, 33kV, 22/11 kV Bus, 22/11 kV Line	
Connection unit charge	The connection unit calculation applies the connection unit charge (per day) multiplied by the customer's number of connection units as advised individually to each customer.
Excess reactive power charge	The excess reactive (kVAr) power charge is calculated monthly based on the kVAr level at the time of each customer's individual monthly kVA peak. To the extent the actual kVAr exceeds the customer's permissible kVAr quantity (determined by the customer's authorised demand and the customer's compliant power factor), excess kVAr charges are applied.
CAC optional tariffs	
Seasonal TOU Demand CAC Higher Voltage, 22/11 kV Bus, 22/11 kV Line	
Opt-in (and opt-out) arrangements	Generally a customer (or their retailer) must request a tariff change to opt in to these tariffs. This is subject to suitable metering. From 1 March 2018, any new CAC premise connections will default to the STOUD where no network tariff has been advised to Ergon Energy

<table>
<tr><th colspan="2">Application of tariff and charges</th></tr>
<tr><td>Connection unit charge</td><td>The connection unit calculation applies the connection unit charge (per day) multiplied by the customer's number of connection units as advised individually to each customer.</td></tr>
<tr><td>Excess reactive power charge</td><td>The excess reactive (kVAr) power charge is calculated monthly based on the kVAr level at the time of each customer’s individual monthly kVA peak. To the extent the actual kVAr exceeds the customer’s permissible kVAr quantity (determined by the customer’s authorised demand and the customer's compliant power factor), excess kVAr charges are applied.</td></tr>
<tr><td>Time periods</td><td><table>
<tr><td>Peak demand</td><td>10:00am to 8:00pm on summer weekdays</td></tr>
<tr><td>Capacity charge (off-peak)</td><td>All times during non-summer months and all times during summer months excluding demands occurring during the peak window of 10.00am to 8.00pm on summer weekdays</td></tr>
<tr><td>Volume charge (off-peak)</td><td>Applies to all metered consumption during non-summer months.</td></tr>
</table>
Note: ‘Summer’ is defined as the months of December, January and February.</td></tr>
<tr><td>Actual demand peak charge</td><td>The peak demand calculation uses the maximum kVA demand in any single half hour at any time during the peak demand period in each summer month.</td></tr>
<tr><td>Capacity off-peak charge</td><td>The capacity off-peak charge calculation uses the maximum of authorised kVA demand or the monthly actual kVA maximum demand during the off-peak window which is all times during non-summer months and all times during summer months excluding demands occurring during the peak window of 10:00am to 8:00pm on summer weekdays.</td></tr>
<tr><td>Volume off-peak charge</td><td>The off-peak volume calculation uses total metered kWh consumption at all times during non-summer months.</td></tr>
</table>

Appendix 2: Compliance matrix

Ergon Energy's compliance with the NER and the AER's Distribution Determination is described throughout this Pricing Proposal. For ease of reference, a summary of the obligations and how we have demonstrated compliance in this Pricing Proposal is provided below.

Table A2.1: Compliance obligations under the NER

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
5.5(h) and (i)	Ergon Energy must pass through to a connection applicant the amount (calculated in accordance with paragraph (i)) for the locational component of prescribed TUoS services that would have been payable by Ergon Energy to Powerlink had the connection applicant not been connected to its distribution network ('avoided charges for the locational component of prescribed TUoS services').	Section 3.3.3 and Table 3-8.
6.1.4(a) and (b)	Ergon Energy must not change a distribution network user DUoS charges for the export of electricity generated by the user into the distribution network. This does not, however, preclude charges for the provision of connection services	Section 3.2.2 provides further explanation on DUoS charging arrangements for generators. As highlighted in Section 1.8 our Connection Policy sets out when connection charges may be payable for connection services. This document is published on Ergon Energy's website.
6.18.1A(c)	Ergon Energy must comply with the tariff structure statement approved by the AER and any other applicable requirements in the NER, when Ergon Energy is setting the prices that may be charged for direct control services.	Tariffs calculated as part of this Pricing Proposal have been developed consistent with our TSS. Ergon Energy has demonstrated compliance with our AER-approved TSS throughout this Pricing Proposal.
6.18.1C(a)(1) and (2)	No later than four months before the start of a regulatory year (other than the first regulatory year of a regulatory control period), Ergon Energy may notify the AER, affected retailers and affected of a new proposed tariff (a relevant tariff) that is determined other than in accordance with Ergon Energy's Tariff Structure Statement , if the following conditions are satisfied: 1) the forecast revenue from the relevant tariff during each regulatory year in which the tariff is to apply is not greater than 0.5 per cent of Ergon Energy's annual revenue requirement for that regulatory year (the individual threshold); and 2) the forecast revenue from the relevant tariff, as well as from all other relevant tariffs, during each regulatory year in which those tariffs are to apply is no greater than one per cent of Ergon Energy's annual revenue requirement for that regulatory year (the cumulative threshold).	Section 5.3.2.

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
6.18.2(a)(2)	Ergon Energy must submit to the AER, at least 3 months before the commencement of the second and each subsequent regulatory year of the regulatory control period, a further pricing proposal (an annual pricing proposal) for the relevant regulatory control period.	Our Pricing Proposal was submitted to the AER by the appropriate date.
6.18.2(b)(2)	Ergon Energy's Pricing Proposal must set out the proposed tariffs (including the tariffs and classes of Alternative Control Services) for each tariff class specified in the tariff structure statement for the relevant regulatory control period.	Tariffs for Standard Control Services are set out in Section 2.1 and 2.2, and in Appendix 1 . Tariff schedule is provided (confidential) Tariff Approval Model and Attachment 1. Tariffs for Alternative Control Services are set out in Section 4.1. Tariff schedule for Alternative Control Services is provided in (confidential) Tariff Approval Model and Attachment 1. The 2018-19 tariffs and tariff structures for Standard Control Services and Alternative Control Services are consistent with our TSS.
6.18.2(b)(3)	Ergon Energy's Pricing Proposal must 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 2.2 and Appendix 1. For Alternative Control Services, the charging parameters are set out in Section 4.2 and 4.3. These are fixed by the control mechanism imposed by the AER. There are two broad types of charges (fixed charges and quoted prices), with several charging parameters. Refer to Section 9 of our TSS.
6.18.2(b)(4)	Ergon Energy's Pricing Proposal must set out the expected weighted average revenue for each tariff class related to Standard Control Services for the relevant regulatory year and also for the current regulatory year.	Section 3.2.4.
6.18.2(b)(5)	Ergon Energy's Pricing Proposal must 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.	Section 5.2.
6.18.2(b)(6)	Ergon Energy's Pricing Proposal must 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.	Section 3.3.
6.18.2(b)(6A)	Ergon Energy's Pricing Proposal must 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.	Section 3.4

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
6.18.2(b)(6B)	Ergon Energy's Pricing Proposal must describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria.	There have been no changes to the jurisdictional schemes since their last jurisdictional scheme approval dates.
6.18.2(b)(7)	Ergon Energy's Pricing Proposal must demonstrate compliance with the NER and any applicable distribution determination, including the tariff structure statement for the relevant regulatory control period.	This table and A2.2 demonstrate how Ergon Energy complies with the NER, the Distribution Determination and its TSS throughout this Pricing Proposal.
6.18.2(b)(7A)	Ergon Energy's Pricing Proposal must demonstrate how each proposed tariff is consistent with the corresponding indicative pricing levels for the relevant regulatory year as set out in the relevant indicative pricing schedule, or explain any material differences between them.	Attachment 2 sets out our revised indicative pricing levels for 2019-20, updated to take into account this Pricing Proposal. Differences between 2018-19 indicative pricing levels (as set out in our 2017-18 Indicative Pricing Schedule) and the proposed 2018-19 tariffs included in Attachment 1 and the (confidential) Tariff Approval Model.
6.18.2(b)(8)	Ergon Energy's 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.	Section 5.3. How these changes comply with the NER and any applicable Distribution Determination is set out in this table and Table A2.1.
6.18.2(d)	At the same time As Ergon Energy submits its pricing proposal, Ergon Energy must submit a revised indicative pricing schedule which sets out, for each tariff and for each remaining regulatory year of the regulatory control period, the indicative price levels determined in accordance with the tariff structure statement and updated so as to take into account the pricing proposal	Our revised indicative pricing schedule, updated to take into account this Pricing Proposal is set out in Attachment 2. Indicative prices contained in the schedule have been calculated consistent with methodologies outlined in our TSS.
6.18.2(e)	Where Energex submits an annual pricing proposal, the revised indicative pricing schedule referred to in clause 6.18.2(d) must also set out, for each relevant tariff under clause 6.18.1C, the indicative price levels for that relevant tariff for each of the remaining regulatory years of the regulatory control period, updated so as to take into account that pricing proposal.	Attachment 2 includes indicative prices for the Lifestyle tariff offered under clause 6.18.1C.
6.18.3(b)	Ergon Energy's Pricing Proposal must 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 2.1and4.1. Further information about tariff assignment is provided in our TSS.
6.18.3 (c)	Ergon Energy's Pricing Proposal must 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 2.1and 4.1 respectively. Further information on how we set out tariff classes is provided in our TSS.

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
6.18.3(d)(1) and (2)	Ergon Energy's Pricing Proposal must demonstrate that tariff classes are formed based on groupings of customers on an economically efficient basis, and with regard to the need to avoid unnecessary transaction costs.	A description of how tariff classes group customers on an economically efficient basis is set out in Sections 2.1 and 4.1, and in our TSS.
6.18.5(a),(b) and (d)	Subject to clause 6.18.5(c), Ergon Energy's tariffs must comply with the pricing principles set out in clause 6.18.5(e) to (j). Ergon Energy must comply in a manner that will contribute to the achievement of the *network pricing objective* outlined in clause 6.18.5(a).	Our TSS details how we have applied the pricing principles contained in the NER in developing our tariff structures and tariffs for the 2017 to 2020 period. The AER approved Ergon Energy's TSS on 28 February 2017. Tariffs calculated as part of this Pricing Proposal have been developed consistent with our TSS.
6.18.5(c)	Ergon Energy's tariffs may vary from tariffs which would result from complying with the pricing principles only: (1) To the extent permitted under clause 6.18.5(h) which requires Ergon Energy to consider the impact of annual charges in tariffs on customers (2) To the extent necessary to give effect to the pricing principles set out in 6.18.5 (i) and (j), which relates to tariff simplicity, and Ergon Energy's compliance with the NER and other regulatory instruments.	Section 5.1.2. Our TSS also addresses how we apply the pricing principles contained in the NER.
6.18.5(e)(1) and (2)	Ergon Energy's Pricing Proposal must demonstrate that revenue from a tariff class lies on or between the stand alone and avoidable cost.	Sections 3.2.6 and4.7.1.
6.18.5(f)	Ergon Energy's Pricing Proposal must demonstrate that each tariff be based on the Long Run Marginal Cost (LRMC) of providing the service to customers assigned to that tariff, with the method of calculating such costs and manner in which that method is applied, to be determined have regard to: (1) the costs and benefits associated with calculating, implement and applying that method (2) the additional costs likely to be associated with meeting demand from customer that are assigned to that tariff at times of greatest utilisation of the relevant part of the distribution network. (3) the location of customers assigned to that tariffs and the extent to which costs vary between different locations in the distribution network.	Sections 3.2.7 and 4.7.2. Additional information on our LRMC methodology for Standard Control Services is contained in Appendix B of our *Supporting Information - Revised TSS* document.

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
6.18.5(g)	Ergon Energy's Pricing Proposal must demonstrate that expected revenue from each tariff reflects: (1) total efficient costs of service customers assigned to that tariff; (2) when summed with revenue expected from all other tariffs, permits Ergon Energy to recover expected revenue for the service in accordance with the Distribution Determination; and (3) comply with sub-paragraphs (1) and (2) in a way that minimised distortion to the price signals for efficient usage that would result from tariffs that comply with the pricing principles set out 6.18.5(f)	Section 3.2.8 sets out our approach for Standard Control Services. Section 4.7.3 sets out our considerations for Alternative Control Services.
6.18.5(h)	Ergon Energy's Pricing Proposal must demonstrate that Ergon Energy has considered the impact on customers of changes in tariffs from the previous regulatory year. Where tariffs are varied from complying with the pricing principles in clause 6.18.5(e) to (g), demonstrate Ergon Energy has had regard to : (1) the desirability for tariffs to comply with the pricing principles in clause 6.18.5(f) and (g), albeit after a reasonable period of transition (2) the extent to which customer can choose the tariff to which they are assigned (3) the extent to which customer are able to mitigate impact of changes in tariffs through their usage decisions.	Sections 5.1.1. Further discussions are also available in our TSS.
6.18.5(i)	Ergon Energy's Pricing Proposal must demonstrate that the structure of each tariff is reasonably capable of being understood by customers.	Section 3.2.9. Further information on how we meet this pricing principle is provided in our TSS.
6.18.5(j)	Ergon Energy's Pricing Proposal must demonstrate that each tariff complies with the NER and all applicable regulatory instruments.	Ergon Energy confirms that our 2018-19 tariffs have been developed to be compliant with the NER and the AER's Distribution Determination. Ergon Energy has demonstrated this throughout this Pricing Proposal and associated attachments. A summary of our compliance with these obligations is set out in this appendix.
6.18.6 (a) and (b)	Ergon Energy's Pricing Proposal must 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.	Section 3.2.5 and the (confidential) Tariff Approval Model.
6.18.6(c)(1) and (2)	Ergon Energy's Pricing Proposal must demonstrate the "permissible percentage" has been calculated in accordance with the definition set out in this clause of the NER.	Section 3.2.5 and the (confidential) Tariff Approval Model.

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
6.18.6(d)(1), (2),(3) and (4)	Ergon Energy's Pricing Proposal must demonstrate that designated pricing proposal charges (TUOS), pass throughs and jurisdictional scheme amounts were removed from the calculation of the side constraint.	Section 3.2.5 and (confidential) Tariff Approval Model.
6.18.7(a)	Ergon Energy's Pricing Proposal must demonstrate that the tariffs passed on, to customers, are the designated pricing proposal charges (TUOS) to be incurred by Ergon Energy for TUOS services.	Section 3.3.
6.18.7(b)	Ergon Energy's Pricing Proposal must demonstrate that the designated pricing proposal charges (TUOS) passed on to customers do not exceed the forecast charges adjusted for over or under recovery.	Section 3.3.
6.18.7(c)(1), (2) and (3)	Ergon Energy's Pricing Proposal must demonstrate that any designated pricing proposal charges (TUOS) over or under recovery, being the difference between the amounts 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.	Section 3.3.
6.18.7(d)	Ergon Energy must demonstrate that it does not recover TUOS to the extent these are: (1) recovered through Ergon Energy's annual revenue requirement; (2) recovered through tariffs designed to pass on jurisdictional scheme amounts under clause 6.18.7A; or (3) recovered from another DNSP	Section 3.3.
6.18.7A (a), (b) and (c)	Ergon Energy's Pricing Proposal must demonstrate that tariffs passed on to customers are the jurisdictional scheme amounts to be incurred by Ergon Energy for approved jurisdictional schemes in accordance with 6.18.7A of the NER.	Section 3.4.
6.18.8(a)(3)	The AER must approve a pricing proposal if the AER is satisfied that all forecasts associated with the proposal are reasonable.	Ergon Energy notes this is at the discretion of the AER to decide. However, Ergon Energy has provided information on forecasts underpinning this Pricing Proposal in Section3.5.
6.18.9(a)(1)	Ergon Energy's Pricing Proposal must demonstrate that the tariff structure statement is maintained on Ergon Energy's website.	Ergon Energy's approved TSS and supporting attachments are published on Ergon Energy's website.
6.18.9(a)(2)	Ergon Energy's Pricing Proposal must demonstrate that the indicative pricing schedule is maintained on Ergon Energy's website.	This Pricing Proposal, including our updated indicative pricing schedule (Attachment 2), will be published on Ergon Energy's website.
6.18.9(a)(3)	Ergon Energy must maintain on its website a statement of its tariff classes and tariffs applicable to each class.	A number of Ergon Energy's supporting pricing documents contain information on our tariff classes and tariffs applicable to each class.
6.18.9(b)	Ergon Energy must publish all information set out in clause 6.18.9(a) its website 5 business days after the AER publishes Ergon Energy's approved pricing proposal.	This Pricing Proposal and non-confidential supporting attachments will be published on Ergon Energy's website by the appropriate date.

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
6.19.2(a) and (b)	Subject to the Law and the NER, all information about a service applicant or distribution network user used by Ergon Energy for the purpose of distribution service pricing is to be kept confidential. No requirement in the NER to publish information about a tariff class is to be construed as requiring publication of information about an individual retail customer.	Ergon Energy does not publish site-specific information relating to individual customers. Our confidentiality claims are set out in Appendix 4.

Table A2.2: Compliance with the Distribution Determination

Obligation	Demonstration of compliance in this Pricing Proposal
Ergon Energy must demonstrate that our revenue is consistent with the TAR formula set out in Figure 14.1 of Attachment 14 of the Distribution Determination.	This is demonstrated in Section 3.2.1.
For Standard Control Services, apply the X factor for each year of the regulatory control period as determined in the PTRM and annually revised for the return on debt update in accordance with the formula specified in Attachment 3 – rate of return – of the Distribution Determination.	Section 3.2.1.
To the extent possible, Ergon Energy's pricing proposal should publicly disclose the separate charging parameters relating to DUOS, designated pricing proposal charges and jurisdictional scheme amount.	Appendix 1.
Ergon Energy must calculate the DMIS adjustment using the method set out in the DMIS and add or deduct this amount from the TAR in 2016–17.	Not applicable in 2018-19.
Ergon Energy must demonstrate the side constraints applying to the price movements of each tariff class are consistent with the formula in Figure 14.2 of Attachment 14 of the Distribution Determination.	Section 3.2.5.
Ergon Energy must maintain a DUoS unders and overs account in accordance with appendix A of Attachment 14 of the Distribution Determination. The expected closing balance at the end of each regulatory year t should be as close as practicable to zero.	Section 3.2.1.
Ergon Energy must maintain a TUOS unders and overs account in accordance with appendix B of Attachment 14 of the Distribution Determination. The expected closing balance at the end of each regulatory year t should be as close as practicable to zero.	Section 3.3.5.
Ergon Energy must maintain a jurisdictional scheme unders and overs account in accordance with appendix C of Attachment 14 of the Distribution Determination. The expected closing balance at the end of each regulatory year t should be as close as practicable to zero.	Section 3.4.1.
Set out how we will review and assess the basis on which a customer is charged, where the charging parameters for a particular tariff result in a basis of charge that varies according to the customer's usage or load profile.	Sections 2.3 and 4.6.

Obligation	Demonstration of compliance in this Pricing Proposal
Apply the public lighting formula set out in Figure 16.1 of Attachment 16 of the Distribution Determination to determine public lighting charges.	Section 4.3.1, and (confidential) Tariff Approval Model.
Apply the fee based ancillary network services formula set out in Figure 16.2 of Attachment 16 of the Distribution Determination to determine prices for fee based services.	Section 4.3.1, (confidential) Tariff Approval Model.
Apply the quoted services formula set out in Figure 16.3 of Attachment 16 of the Distribution Determination to determine prices for quoted services.	Section 4.3.2. In practice, we will develop a user-specific quote based on the requestor's needs. This will be determined using the quoted services formula.
Apply the price cap formula set out in section 16.3.1.3 of Attachment 16 of the Distribution Determination to determine prices for Default Metering Services.	Section 4.3.1, and (confidential) Tariff Approval Model.

Appendix 3 – Glossary

Abbreviations

ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AS	Australian Standard
ATMD	Any Time Maximum Demand
CAC	Connection Asset Customer
CAM	Cost Allocation Method
Capex	Capital expenditure
CPI	Consumer Price Index
CT	Current transformer
DCOS	Distribution Cost of Supply
DLF	Distribution Loss Factor
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DPPC	Designated pricing proposal charge
DUoS	Distribution Use of System
EDNC	Electricity Distribution Network Code
EEQ	Ergon Energy Queensland Pty Ltd
EG	Embedded Generator
Energex	Energex Limited
Ergon Energy	Ergon Energy Corporation Limited
Excess kVAr	Excess reactive power charge
FiT	Feed-in tariff
GWh	Gigawatt hour
HV	High voltage
IBT	Inclining Block Tariff
ICC	Individually Calculated Customer
kV	Kilovolt
kVA	Kilovolt-ampere
kVAr	Kilovolt-ampere reactive
kW	Kilowatt
kWh	Kilowatt hour
Law	National Electricity Law
LED	Light emitting diode

LOB	Line of Business
LRMC	Long Run Marginal Cost
LV	Low voltage
MWh	Megawatt hour
NEM	National Electricity Market
NER	National Electricity Rules
Opex	Operating expenditure
p.a.	Per annum
PTRM	Post Tax Revenue Model
PV	Photovoltaic
QCA	Queensland Competition Authority
QPC	Queensland Productivity Commission
RIN	Regulatory Information Notice
SAC	Standard Asset Customer
SPARQ	SPARQ Solutions Pty Ltd
STOUD	Seasonal Time-of-Use Demand
STOUE	Seasonal Time-of-Use Energy
STPIS	Service Target Performance Incentive Scheme
TAR	Total Annual Revenue
TNSP	Transmission Network Service Provider
TOU	Time-of-Use
TSS	Tariff Structure Statement
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital

Definitions

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, Default Metering Services and Public Lighting Services.
Annual revenue adjustment	Annual adjustments made to Ergon Energy's smoothed revenue requirement for Standard Control Services for matters such as out-turn inflation, the return on debt, STPIS, pass throughs, and the difference between forecast and actual revenue received for DUoS charges.
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 National Electricity Market (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 Law, NER, National Gas Law and Rules, and the National Energy Retail Law and Rules.
Authorised demand	The maximum demand permitted to be imported or exported to the network by a network user, based on the nature of their connection. The authorised demand is either: • negotiated with the network user and detailed in their connection contract • determined by Ergon Energy as part of the annual price setting process, using historical data.
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 Distribution Network Code (EDNC)).
Capacity charge	A type of charge (charging parameter) included in Ergon Energy's 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.

Capital contribution	A capital contribution is a prepayment for the provision of Direct Control Services. A capital contribution may be charged to a customer if the new connection or modification for an existing connection is required to the network to accommodate the connection/modification. Ergon Energy's Connection Policy sets out circumstances in which a capital contribution may be required and details how the capital contribution to be charged to a customer is calculated.
Charging parameter	The constituent elements of a tariff (as defined in the NER).
Connection	The physical link to or through a transmission network or distribution network.
Connection Asset Customer (CAC)	Typically reflects those customers: • with required capacity above 1,500 kVA • with energy consumption typically greater than 4 GWh p.a. (but less than 40 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.
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 the 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.

Default Metering Services	A type of Alternative Control Service. Relates to: • Type 5 and 6 meter installation and provision (before 1 July 2015) • Type 5 and 6 meter installation and provision (on or after 1 July 2015), where the replacement meter is initiated by Ergon Energy as a distributor • Type 5 and 6 metering maintenance, reading and data services.
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.
Demand charges	A type of charge (charging parameter) included in Ergon Energy's network tariff structures. Within a tariff structure, demand charge rates can be: • applied year round or seasonally (with different peak and off-peak rates) • calculated based on: – a single period in the month – the maximum demand within a peak demand window – an average of demands within a demand window. Some tariff structures include a floor (the demand charge must include at least the rate times 'X' demand) or a threshold (the demand charge is only calculated for demand recorded above a particular level).
Designated pricing proposal charges (DPPC)	Typically referred to as 'TUOS' in this Pricing Proposal. See the 'Transmission Use of System (TUOS) charge' definition below.
Direct Control Service	Distribution services subject to economic regulation by the AER under the NER. Direct Control Services are further subdivided into Standard Control Services and Alternative Control Services.
Distribution Cost of Supply (DCOS) Model	The Ergon Energy model used to allocate costs to network users and convert the revenue cap, transmission-related costs and jurisdictional scheme amounts into network tariffs.
Distribution Determination	The AER's Distribution Determination sets the revenue and pricing control regime that Ergon Energy must comply with for the current regulatory control period (i.e. 2015–20).
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 recovers costs associated with connection services and/or use of the distribution network for the conveyance of electricity (i.e. Standard Control Services).

East Zone	Those areas where the network users are supplied from the distribution system connection to the national grid and have a relatively low distribution cost to supply. The local government areas covered by the East Zone are located in the *Information Guide for Standard Control Services*.
Electricity Market	Means the NEM as administered by the Australian Energy Market Operator.
Embedded Generator (EG)	EGs are those network users that export energy into the distribution system, except for network users with micro-generation facilities of the kind contemplated under AS 4777.1 – 2005. 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.[36]
Energy	The amount of electricity consumed by a customer (or all customers) over a period of time. Energy is measured in terms of watt hours (Wh), kilowatt hours (kWh), megawatt hours (MWh) or gigawatt hours (GWh).
Excess reactive power charge (Excess kVAr)	A type of charge (charging parameter) included in Ergon Energy's network tariff structures which is applied against the kVAr used by a customer that exceeds what they would be entitled to use at their minimum compliant power factor at authorised demand.
Fee based services	A type of Alternative Control Service which Ergon Energy undertakes at the request of an identifiable customer, retailer or appropriate third party which is levied as a separate charge. The costs of providing the service (and therefore price) can be assessed in advance of the service being requested.
Fixed charge	A type of charge (charging parameter) included in Ergon Energy's network tariff structures which is levied on a fixed dollar amount per day or fixed dollar amount per day per device (as is the case for unmetered supply).
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.

36 The load side will be classified as an ICC, CAC or SAC, and a separate network tariff will apply.

Individually Calculated Customer (ICC)	Typically reflects those customers: • with energy consumption typically greater than 40 GWh 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.
Isolated generation	Those areas supplied from Ergon Energy's isolated generation assets, except for the Mount Isa system. Includes communities in Western Queensland, the Gulf of Carpentaria, Cape York, various Torres Strait Islands, Palm Island and Mornington Islands. These areas are not subject to economic regulation by the AER, but are regulated by the Queensland Government.
Jurisdictional scheme amount	In respect of a jurisdictional scheme, the amounts a DNSP is required under the jurisdictional scheme obligations to: (a) pay to a person (b) pay into a fund established under an Act of a participating jurisdiction (c) credit against charges payable by a person, or (d) reimburse a person, less any amounts recovered by the DNSP from any person in respect of those amounts other than under the NER (as defined in the NER).
Jurisdictional scheme charges	Component of the network tariff which passes through jurisdictional scheme amounts.
kVA	1,000 Volt-Ampere which is a measure of the apparent power flow which is a measure of the total capacity required to supply a customer's load.
kVAr	1,000 Volt-Ampere reactive which is a measure of reactive power.
kW	1,000 Watts which is a measure of the real component of power being consumed by the consumer's load.
Load factor	Measure of the percentage of time a load is used in any given period. Loads used 24 hours per day, 7 days a week have a load factor of one (1) or 100 per cent.
Long Run Marginal Cost (LRMC)	The cost of an incremental change in demand over a period of time in which all factors of production required to provide those services can be varied (as defined in the NER). This definition incorporates the investment required over time to maintain and expand capacity in the network to meet future demand.

Low Voltage (LV)	Refers to the sub 11 kV network.
Major customer	Are ICCs, CACs or EGs.
Maximum demand	The maximum demand recorded at a customer's individual meter or the maximum demand placed on the electrical distribution network system at any time or at a specific time or within a specific time period, such as a month. Maximum demand is an indication of the capacity required for a customer's connection or the electrical distribution network.
Megawatt hour (MWh)	1,000 kilowatt hours
Mount Isa Zone	Those areas supplied from the isolated Mount Isa system. This zone is not connected to the national grid and would normally be excluded from the application of the NER. However, under the *Electricity – National Scheme (Queensland) Act 1997,* the Queensland Government has transferred responsibility for the economic regulation of the Mount Isa-Cloncurry supply network to the AER. The local government areas covered by the Mount Isa Zone are located in the *Information Guide for Standard Control Services*.
National Electricity Market (NEM)	The interconnected electricity grid covering Queensland, New South Wales, Victoria, Tasmania, South Australia and the Australian Capital Territory.
National Electricity Rules (NER)	Rules made under the Law which govern the operation of the NEM.
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, and jurisdictional scheme amounts. Network tariffs comprise DUoS, TUOS and jurisdictional scheme charges.
Network user	There are four network user groups included in Ergon Energy's network tariff structures – ICCs, CACs, SACs and EGs. For the purposes of our network pricing documents, the term 'network user' refers to both a 'customer' and an 'EG'.
Power factor	The ratio of kW to kVA at a metering point during a defined period.
Premises	Means premises owned or occupied by the customer.
Public Lighting Services	A type of Alternative Control Service. Relates to the provision, construction and maintenance of public lighting assets owned by Ergon Energy, and emerging public lighting technology. Also encompasses public lighting exit fees.
Public lights – Major	Includes the following lantern types: • Metal Halide – above 125 W • Mercury Vapour – above 125 W • High Pressure Sodium – above 100 W.

Public lights – Minor	Includes the following lantern types: • Compact Fluorescent – all wattages • Fluorescent – all wattages • Metal Halide – up to and including 125 W • Incandescent – all wattages • Low Pressure Sodium – all wattages • LED – all wattages • Mercury Vapour – up to and including 125 W • High Pressure Sodium – up to and including 100 W.
Quoted services	A type of Alternative Control Service. Similar to fee based services, but they are priced on application as the nature and scope of these services is variable and the cost (and therefore price) is specific to the individual requestor's needs.
Regulatory control period	The regulatory control period is a five (5) year period set down by the AER. The current regulatory control period is 2015–16 to 2019–20.
Regulatory year	Is a specific financial year within a regulatory control period.
Residential customer	Means a customer who acquires electricity for domestic use (as defined in the Queensland EDNC).
Revenue cap	The TAR, as determined using the revenue cap formula set out in the Distribution Determination.
Side constraint	Refers to the percentage by which the expected weighted average revenue to be raised from a Standard Control Service tariff class is allowed to increase by between regulatory years. Side constraints are intended to set a limit (or constraint) on the level of distribution price increase to be experienced by customers from one year to the next within a regulatory control period.
Standard Asset Customer (SAC)	Typically reflects those customers with annual energy consumption below 4 GWh p.a. Includes customers with micro-generation facilities (such as small scale PV generators) of the kind contemplated under AS 4777.1 – 2005. The SAC group is further subdivided into network tariff categories based on whether: • the customer's connection is metered or unmetered • the customer's consumption relates to residential or business use • the customer is taking supply at high voltage or low voltage • the customer's consumption is above or below 100 MWh p.a. • the customer has a meter installed capable of recording demand • the customer's supply is capable of being controlled by Ergon Energy.
SAC Large	Those SACs that typically use between 100 MWh p.a. and 4 GWh p.a.
SAC Small	Those SACs that typically use less than 100 MWh p.a.

Standard Control Service	A distribution service provided by Ergon Energy that the AER has classified as a Standard Control Service under the NER. Includes network services, some connection services (including small customer connections) and Type 7 metering services. Ergon Energy recovers our costs in providing Standard Control Services through the DUoS component of network tariffs which are billed to retailers.
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 Large 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 for any time demand tariffs and the peak and off-peak demand charges for the STOUD tariffs are applied to the kW amount by which the recorded monthly maximum demand exceeds the relevant threshold. This demand may occur at any time during the month (actual demand charge and off-peak demand charge) or during a set peak period (peak charge). Where the monthly metered maximum demand is less than the demand threshold, the chargeable demand for that month is set to zero.
Time-of-Use (TOU)	A type of network tariff where the price per kWh varies according to when the consumption occurs. The TOU tariff may apply a different price during peak and off-peak periods.
Transmission Use of System (TUOS) charge	Component of the network tariff which passes through costs associated with use of the transmission network. This includes designated pricing proposal charges as defined under the NER plus charges levied on Ergon Energy in relation to Chumvale and three Powerlink connection points.
Unmetered	A customer who takes supply where no meter is installed at the connection point.
Volume charge	A type of charge (charging parameter) included in Ergon Energy's network tariff structures which is calculated using the customer's metered energy (kWh) consumption. It may be based on a flat rate, an inclining block or TOU charging structure (depending on the customer's applicable network tariff).
West Zone	Those areas outside the East Zone and connected to the national grid, which have a significantly higher distribution cost of supply than the East Zone. The local government areas covered by the West Zone are located in the *Information Guide for Standard Control Services*.

Appendix 4 – Confidentiality claims

Table A4.1: Confidentiality template

Title, page and paragraph number of document containing the confidential information	Description of the confidential information	Topic the confidential information relates to	Identify the recognised confidentiality category that the confidential information falls within	Provide a brief explanation of why the confidential information falls into the selected category. If information falls within 'other' please provide further details on why the information should be treated as confidential.	Specify reasons supporting how and why detriment would be caused from disclosing the confidential information.	Provide any reasons supporting why the identified detriment is not outweighed by the public benefit (especially public benefits such as the effect on the long term interests of consumers).
"Ergon Energy Tariff Approval Model.xlsm" All pages	Site-specific network tariff rates, customer data and revenue reconciliation for Individually Calculated Customers, Connection Asset Customers and Embedded Generators	Customer specific prices and data	Other – third party pricing information Personal information	As per clause 6.19.2 of the National Electricity Rules (NER), all information about a service applicant or distribution network user used by a distributor for the purposes of distribution service pricing is confidential information. Further, no requirement in Chapter 6 of the NER to publish information about a tariff class (including the proposed network tariffs) is to be construed as requiring publication of information about an individual retail customer. This spreadsheet feeds tables and models that are incorporated in our pricing proposal and attachments so the majority of the information is available.	The publication of this information would breach the NER and any connection agreements between Ergon Energy and our customers. It may also adversely affect the markets in which our customers operate.	We expect consumers would normally provide information to us on the expectation that this information (or our analysis of this information) would not be released to the public by a third party.

Title, page and paragraph number of document containing the confidential information	Description of the confidential information	Topic the confidential information relates to	Identify the recognised confidentiality category that the confidential information falls within	Provide a brief explanation of why the confidential information falls into the selected category. If information falls within 'other' please provide further details on why the information should be treated as confidential.	Specify reasons supporting how and why detriment would be caused from disclosing the confidential information.	Provide any reasons supporting why the identified detriment is not outweighed by the public benefit (especially public benefits such as the effect on the long term interests of consumers).
				We provide the spreadsheet with relevant links to confidential material to allow the AER to review workings and analysis.		

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