2017–18 Pricing Proposal

Distribution services for 1 July 2017 to 30 June 2018

Version 1.0 – for AER approval

Version control

Version	Date	Summary of changes
1.0	31 March 2017	Initial proposal to the AER for 2017–18.

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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 a Distribution Network Service Provider (DNSP) to around 730,000 customers in regional Queensland. Our service area covers around 97 per cent of Queensland and has approximately 160,000 kilometres of power lines and one million power poles. Around 70 per cent of our network's power lines are radial and service mostly rural areas with very low levels of customers per line kilometre.

1.2 Purpose

Clause 6.18.2(a)(2) of the *National Electricity Rules* (NER)[1] requires Ergon Energy to submit a Pricing Proposal to the Australian Energy Regulator (AER) at least three months before the commencement of the regulatory year.

The AER approves prices for services it classifies as Direct Control Services.[2] This Pricing Proposal assists the AER in approving these prices. It sets out how Ergon Energy's proposed tariffs and/or prices for Direct Control Services in 2017-18 meet the requirements of the NER.

1.3 Classification of services

Direct Control Services are separately classified into Standard 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. Ergon Energy recovers our costs in providing Standard Control Services through network tariffs billed to retailers.

Alternative Control Services are comprised of:

- *Fee based services* – one-off distribution services that Ergon Energy undertakes 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 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.).[3]
- Default Metering Services – relate to:
  - Type 5 and 6 meter installation and provision (before 1 July 2015)

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1 Version 89.
2 NER 6.1.3(b)(2).
3 The prices set out in this Pricing Proposal are examples of potential prices for quoted services.

- 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 DNSP
- Type 5 and 6 metering maintenance, reading and data services.

Ergon Energy recovers our 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.

- *Public Lighting Services* – relate to the provision, construction and maintenance of public lighting assets owned by Ergon Energy, and emerging public lighting technology. Ergon Energy recovers our costs of providing Public Lighting Services through a daily public lighting charge billed to retailers. We also charge a one-off exit fee, 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 Appendix 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 Ergon Energy can earn, and the prices that Ergon Energy can charge for certain services provided by means of, or in connection with, our distribution system.

1.4.1 Distribution Determination

On 29 October 2015, the AER made its Distribution Determination for regulated distribution services provided by Ergon Energy.[5] The Distribution Determination effectively sets the revenue and pricing control regime that Ergon Energy must comply with over the current regulatory control period (i.e. 2015–20) for these services.

It also details how Ergon Energy must report on the recovery of jurisdictional scheme amounts. For Ergon Energy, this includes:

- feed-in tariff (FiT) payments made under the Queensland Government's Solar Bonus Scheme
- the energy industry levy payable under our Distribution Authority.

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 changes were new obligations for DNSPs, including Ergon Energy, to develop prices that better reflect the costs of providing services to customers so they can make informed decisions about how they use electricity.

As part of this new framework, Ergon Energy must submit a Tariff Structure Statement (TSS) to the AER. The TSS sets out our proposed tariff structures for the regulatory control period and how we have applied the new pricing principles in developing these structures. The AER approved Ergon Energy's TSS for the 2017 to 2020 period[6] on 28 February 2017.

[4] Outside of our LED transition program.

[5] This Distribution Determination replaces the preliminary decision released by the AER on 30 April 2015. The preliminary decision was used to set prices for 2015–16.

[6] Due to transitional arrangements, our current TSS covers 2017-18 to 2019-20 only.

The TSS interfaces with Ergon Energy's Pricing Proposal, and each Pricing Proposal must be consistent with the approved TSS. The TSS will apply to Ergon Energy for the first time in 2017-18.

As much of the content in our TSS around adherence to the pricing principles and tariff development is directly relevant to our 2017-18 prices, several sections of this Pricing Proposal therefore refer to the TSS for further information.

1.4.3 Pricing principles and objectives

In setting the level (or price) of tariffs, Ergon Energy must comply with a number of pricing principles outlined in clauses 6.18.5(e) to (j) of the NER. For example, the NER require Ergon Energy to:

- set each tariff "based on" the Long Run Marginal Cost (LRMC) of providing network services to consumers assigned to the tariff (clause 6.18.5(f))
- adjust LRMC based prices to recover total efficient costs in a way that minimises distortions to the efficient usage decisions of consumers (clause 6.18.5(g)(3))
- consider the impact on consumers of changes to tariffs between regulatory years, and adjust prices to the extent necessary to meet consumer impact principles and enable a smooth transition to cost reflective tariffs (clause 6.18.5(h))

Expected revenue recovered from our tariffs must also:

- for each tariff class, be between the stand alone costs of serving those customers and the avoidable costs of not serving those customers (clause 6.18.5(e))
- for each tariff, reflect our efficient costs of serving customers assigned to that tariff (clause 6.18.5(g)(1))
- permit Ergon Energy to recover the expected revenue in accordance with the AER's Distribution Determination (clause 6.18.5(g)(2)).

More detailed information on our 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 services through Schedule 8 of the *Electricity Regulation 2006*. Since the price caps are imposed through legislation, they take precedence over the prices approved by the AER. This means Ergon Energy cannot recover our full costs of providing these services and the shortfall is borne by us.

It is important to note that the prices contained in Appendix 1 reflect the tariffs derived under the tariff-setting process and, depending on the type of service, the prices in Appendix 1 may be higher than the prices customers will be charged. The *Price List for Alternative Control Services* will provide the rates applicable for 2017-18 as a result of Schedule 8 maximum price caps, and hence the prices customers will be charged.

1.5 Summary of changes

Ergon Energy is proposing a number of changes to our Alternative Control Services and to our network tariffs for Standard Control Services in 2017-18. Key changes are summarised in Table 1.1 and Table 1.2 below.

Further detail on the 2017-18 changes is set out in Section 5.3.

Table 1.1: Network tariff changes

Network user group	Tariff changes
ICC	○ No change to tariff structures.
CAC	○ As noted in our TSS and 2016-17 Pricing Proposal we are proceeding with the introduction of an excess reactive power charge (excess kVAr charge) for our CAC network tariffs in 2017-18. ○ As foreshadowed in our TSS, any new premises and customers moving into existing premises will be assigned to the STOUD tariff in 2017-18. Subsequently, from 1 March 2018[7], any new CAC premise connections will 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 CAC anytime demand tariffs.
SAC Large	○ The TSS, made provision for any new premises and customers moving into existing premises (with the required metering) from 1 July 2017 to be assigned to the STOUD tariff. From 1 March 2018[7], any new SAC Large premise connections will 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 one of our other SAC Large anytime demand tariffs. ○ Consistent with intentions noted in our 2016-17 Pricing Proposal, and the approved TSS, Ergon Energy is continuing to phase out Demand High Voltage tariffs. From 1 July 2017 this tariff will no longer be available in the East Zone[8]. Existing premises will be reassigned to either the STOUD tariff or one of the SAC Large general anytime demand tariffs.
SAC Small	○ No change to tariff structures.
EG	○ No change tariff structures. However we are continuing to monitor the volume of new connections, and may look to introduce standardised rates in future Pricing Proposals.

Table 1.2: Alternative Control Services changes

Service	Changes
Fee based services	
Upfront meter charges (Install new or replacement Type 5 and 6 meter)	○ From 1 December 2017, it is expected this service will cease[9] with the Power of Choice changes. This means alternative providers will generally be responsible for the installation of new or replacement meters[10].
Temporary connection, not in permanent position – single phase or multi-phase meter	○ The price of this service will be amended during 2017-18 to remove, or disaggregate the metering component that will be subject to contestability from 1 December 2017. Further information on the Power of Choice changes is set out in Section 5.3.1.

[7] Due to operational complexities associated with implementing this business rule prior to the Power of Choice changes, Ergon Energy has decided not to implement the change until after the 1 December 2017. The (further delayed) 1 March 2018 timeframe will also help mitigate the risk of customers having a poor initial experience with the STOUD tariff, by otherwise immediately incurring peak summer charges.

[8] The Demand High Voltage tariffs were phased out in the West and Mt Isa Zones in 2016-17

[9] Ergon Energy is still considering the arrangements for new and replacement metering in our Mount Isa-Cloncurry and Isolated supply networks. This is on the basis that the Power of Choice changes do not apply, as the supply networks are not connected to the national grid and therefore not subject to Chapter 7 of the NER.

[10] Ergon Energy will remain responsible for the maintenance of its existing fleet of Type 5 and 6 meters, including distributor initiated replacements.

Service	Changes
Supply abolishment during business hours	○ The price of this service will be amended during 2017-18 to remove, or disaggregate the metering component that will be subject to contestability from 1 December 2017. Further information on the Power of Choice changes is set out in Section 5.2.1.
Quoted Services	
Customer or retailer requested appointments	○ From 1 December 2017, this service will be expanded to allow charges to be levied on retailers and metering providers for relevant Power of Choice services (e.g. where Ergon Energy attendance is require to isolate power to facilitate a meter installation, or to restore supply where the metering provider's installation is found to be at fault).
Other quoted services including metering related components (various)	○ Power of Choice impacts - appropriate adjustments will be made to the quoted price at the time of the customer's enquiry to remove any metering related components that will no longer be performed by Ergon Energy from 1 December 2017.

1.6 Structure of this document

This Pricing Proposal should be read in conjunction with our approved TSS - *Revised Tariff Structure Statement 2017 to 2020, October 2016*[11]. 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.

This Pricing Proposal is structured as follows:

Chapter	Title	Overview
1	Introduction	Provides an overview of the 2017-18 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 how the 2017-18 Pricing Proposal satisfies the NER and the AER's Distribution Determination in relation to tariff structures and tariff assignment policies for our Standard Control Services.
3	Tariff levels for Standard Control Services	Details how Ergon Energy has set the tariff levels for 2017-18 and how our proposed prices for Standard Control Services meet the requirements of the NER and the AER's Distribution Determination.
4	Alternative Control Services	Outlines how Ergon Energy's tariff structures, tariff assignment policies and proposed 2017-18 prices for Alternative Control Services satisfy the requirements of the NER and the AER's Distribution Determination.
5	Other compliance	Addresses other regulatory requirements which have not been covered in previous chapters
	Appendices	Contains additional supporting information, including: ○ Proposed 2017-18 prices for Standard and Alternative Control Services ○ Compliance matrix ○ Glossary ○ Confidentiality template

[11] Available on Ergon Energy's website at: www.ergon.com.au/network/network-management/network-pricing.

Ergon Energy has 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.

In accordance with the AER's Confidentiality Guideline, Ergon Energy has provided both public and confidential versions of our Pricing Proposal, where required. Our confidentiality claims, including the proportion of confidential material contained within our Pricing Proposal and its attachments and appendices, are set out in Appendix 4. All confidential information in the public documents has been redacted.

1.7 Supporting network pricing documents

In addition to this Pricing Proposal, Ergon Energy has a number of network pricing documents to assist network users, retailers and interested parties understand the development and application of tariffs and connection charges. The documents outlined in Figure 1.1 below provide further information about network tariffs – including tariff assignment, Network Tariff Codes and loss factors – and operational issues relating to Standard and Alternative Control Services.[12]

The *Network Tariff Guide* and the *Price List for Alternative Control Services* will also set out the tariffs and prices for 2017-18 and any other changes that are required as a result of this Pricing Proposal, once approved.

[12] These documents will be available on Ergon Energy's website at: www.ergon.com.au/network/network-management/network-pricing.

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 additional guidance on the compliance requirements of Chapter 6 of the National Electricity Rules (NER), and how Ergon Energy's prices for our Standard and Alternative Control Services meet these requirements
- Submitted to the AER annually, and updated as required

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

Figure 1.1: Supporting network pricing documentation

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 and *retail customers* to whom *alternative control services* are supplied (but a customer for both *standard control services* and *alternative control services* may be a member of 2 or more *tariff classes*).

(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.

2.1 Tariff classes

Consistent with our TSS, Ergon Energy will apply 18 tariff classes for Standard Control Services in 2017-18, as shown in Table 2.1 below.[13] 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)
    - 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.

13 NER, clause 6.18.2(b)(2).

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	●	●	●

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

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

Consistent with clause 6.18.3(c) of the NER, Ergon Energy assigns customers receiving Standard Control Services to one of the tariff classes shown in Table 2.1.

Separately, Ergon Energy provides tariff classes for customers seeking Alternative Control Services, as outlined in Section 4.1.

Finally, clause 6.18.3(d) of the NER requires that a tariff class be constituted with regard to the need to group customers together on an economically efficient basis, and the need to avoid unnecessary transactions costs. This requires a balance to be struck between:

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

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

2.2 Tariffs and tariff structures

Tariff charging parameters

A tariff represents a combination of charges that Ergon Energy applies to a customer (through their retailer) in order to recover network costs. Within each tariff class, a number of tariffs can be offered.

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. Ergon Energy uses six broad types of charges and eight charging parameters for our Standard Control Services (DUOS charges), as 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 optional, LRMC-based tariffs. The charges and charging parameters that have been adopted in 2017-18 for each tariff is consistent with our TSS and are shown in Appendix 1. More detailed information on charges and charging parameters by tariff is available in Chapter 5 of the TSS.

Table 2.2: Types of charges and charging parameters for Standard Control Services

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.
Volume charge	Represented as a rate ($) per kWh. Different parameters apply to this charge for different tariffs. Within a tariff structure, volume charge rates can be flat or be applied to different blocks (based on consumption) or times (peak and off-peak).	Applies to all tariffs except EGs.
Demand charge	Represented as either a rate ($) per kW or a rate ($) per kVA. Different parameters apply to this charge for different tariffs. Within a tariff structure, demand charge rates can be: ○ applied year round or seasonally (with different peak and off-peak rates) ○ calculated based on: – a single period in the month – the maximum demand within a peak demand window – an average of demands within a demand window. Some tariff structures include a floor (the demand charge must include at least the rate times 'X' demand) or a threshold (the demand charge is only calculated for demands recorded above a particular level).	Applies to all tariffs except: ○ Residential IBT ○ Business IBT ○ Residential STOUE ○ Business STOUE ○ Controlled load ○ Unmetered supplies ○ EGs.
Capacity charge	Represented as a rate ($) 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.

Charge	Charging parameter	Application to tariffs
		○ CAC any time demand tariffs ○ CAC STOUD
Connection unit charge	Represented as a rate ($) per connection unit per day.	Applies to the following tariffs: ○ CAC any time demand tariffs ○ CAC STOUD.

2.3 Tariffs by Tariff Class

Clause 6.18.2(b)(2) of the NER requires Ergon Energy to set out the proposed tariffs for each tariff class. Accordingly, the 2017-18 tariffs for Standard Control Services are set out in Appendix 1. Tariff assignment policies

Rule requirement

Clause 6.18.1A(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, Ergon Energy has developed a more detailed document containing our procedures on assigning and reassigning customers to Standard Control Services tariff classes and tariffs. Consistent with NER requirements, these procedures are published in the TSS (refer to Appendix D of our TSS). Ergon Energy will comply with these procedures in 2017-18.

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. Ergon Energy's compliance with this requirement for Standard Control Service tariff classes is set out below.

Review of the charging basis

Ergon Energy 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) of a customer may mean a different network tariff is more applicable, or
- within a network tariff, it is appropriate to change the charging parameter(s) because of changes relating to the customer's usage. For example, an additional charge and charging parameter may be applicable once usage reaches a certain level.

Ergon Energy annually reviews the assignment of customers to our tariff classes as part of the process of developing and submitting our Pricing Proposal to the AER for approval. In undertaking this review, Ergon Energy uses set procedures and specific criteria 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.

In addition to this annual review process, customers and/or retailers can expressly request Ergon Energy to review and change a network tariff assigned to a customer in the event of variation to the customer's usage, load profile or classification as a business or residential customer. Provided Ergon Energy agrees 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.

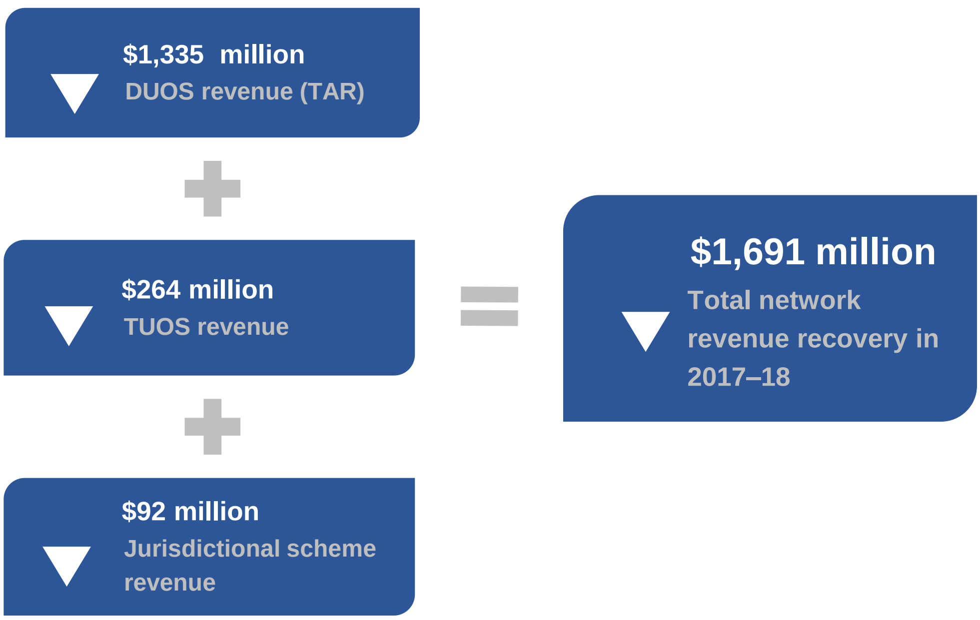
With respect to variations in the basis of charge within a network tariff, Ergon Energy notes that the structure and rates of each charge and charging parameter within a tariff (see Table 2.2) apply equally to each customer assigned to the network tariff, regardless of a customer's individual usage or 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

In 2017-18, the total network revenue that Ergon Energy will need to recover from network users (via tariffs) is approximately $1,691 million.



The amount to be recovered includes Ergon Energy's Total Annual Revenue (TAR) of approximately $1,335 million. This is 8.75 per cent below what we expected to recover from network users in 2016-17.

The TAR reflects Ergon Energy's smoothed expected revenue for 2017-18 plus other annual revenue adjustments. The smoothed expected revenue is determined by taking the smoothed expected revenue for 2016-17 and adjusting it by:

- an annual percentage change in inflation of 1.48 per cent. This is lower than the annual percentage change in inflation that applied in 2016-17 (1.69 per cent)
- a revised X factor, which takes into account an updated return on debt figure for 2017-18 of 5.07 per cent.[14] This is higher than the return on debt figure that applied in 2016-17 (5.06 per cent)
- the s-factor for 2017–18, which relates to our performance under the Service Target Performance Incentive Scheme (STPIS) in 2015-16.[15] This is effectively a positive revenue adjustment.

The other revenue adjustments that will apply in 2017-18 relate to:

- a Distribution Use of System (DUOS) over recovery in 2015-16 (**–** *negative revenue adjustment*)

A detailed discussion on the calculation of the TAR (or revenue cap) is set out below.

Ergon Energy also recovers revenue on behalf of Powerlink and other designated pricing proposal charges (see Section 1.1), and jurisdictional scheme revenue associated with the Solar Bonus Scheme and the energy industry levy (see Section 3.3). As these amounts are excluded from Ergon Energy's TAR (see Section 3.1.1), these amounts are not included in our DUOS charges. These amounts are instead recovered and passed through to customer as separate 'TUOS' and 'jurisdictional scheme' charges which form part of our network tariffs.

3.1 Distribution Use of System (DUOS) charges

3.1.1 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 Figure 14.1 of Attachment 14 of the Distribution Determination, Ergon Energy applies the following formulae when calculating the TAR for a given regulatory year:

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

[14] Under the trailing average portfolio approach, the return on debt, and consequently, the allowed rate of return, will vary each regulatory year. As such, the Post Tax Revenue Model (PTRM) and the smoothed revenue requirement are amended each year to take into account these updated figures.

[15] The s-factor also takes into account the removal of the prior year's s-factor impact.

Where:

TAR_t is the total annual revenue in year t.

p_t^{ij} is the price of component 'j' of tariff 'i' in year t.

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

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

I_t is the final carryover amount from the application of the DMIS from the 2010–15 distribution determination. This amount was calculated using the method set out in the DMIS and deducted from/added to allowed revenue in the 2016-17 pricing proposal.[16]

B_t is 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].

C_t is the sum of adjustments related to:

- feed-in tariff pass through amounts relating to the 2013–14 and 2014–15 regulatory years
- 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 2015–16 year, t–2 is December quarter 2013 and t–1 is December quarter 2014 and in the 2016–17 year, t–2 is December quarter 2014 and t–1 is December quarter 2015 and so on.

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

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

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

The resulting revenue cap for 2017-18, and the underlying calculations, is provided in a separate supporting attachment to this Pricing Proposal (Attachment 1). Ergon Energy confirms that the expected revenue to be collected from our DUOS charges is less than the TAR.

DUOS unders and overs account

Under a revenue cap, our revenues are adjusted annually to clear any under or over recovery of actual revenue collected through DUOS charges. This 'unders and overs' rebalancing process is undertaken as part of annual pricing to ensure 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, for prices set in 2017-18, the adjustment will relate to actual under or over recoveries in the 2015-16 regulatory year.

Appendix A of Attachment 14 of the Distribution Determination requires Ergon Energy to maintain a DUOS unders and overs account, which is to be provided to the AER in this Pricing Proposal. Table 3.1 below sets out Ergon Energy's 2015-16 DUOS over recovery based on information lodged (and audited) in our 2015-16 Annual Reporting Regulatory Information Notice (RIN). Ergon Energy is proposing a further adjustment to actual 2015-16 DUOS revenue to remove unpaid network charges associated with the voluntary administration of GoEnergy Pty Ltd, which was declared a Retailer of Last Resort (ROLR) event on 2 April 2016. This is subject to approval by the AER as part of this Pricing Proposal.

Attachment 1 sets out the calculation of the DUOS unders and overs account, including more detail about Ergon Energy's proposed adjustments.

Table 3.1: Calculation of DUOS unders and overs account

	2015-16 Year t-2 (actual) $'000	2017-18 Year t (forecast) $'000
(A) Revenue from DUOS charges[17]	$1,450,215	$1,334,982
(B) Less TAR for regulatory year =	$1,444,147	$1,334,982
+ Annual revenues (AR_t)	$1,160,467	$1,341,803
+ DMIS carryover amount (I_t)	$0	$0
+ Sum of under or over recoveries (B_t) =	$148,649	($6,821)
+ *Capital contributions/shared assets*	*$81,545*	*$0*
+ *DUOS revenue under/over recovery approved*	*$67,104*	*($6,821)*
+ Sum of pass through adjustments (C_t) =	$135,031	$0
+ *Feed-in tariff cost pass throughs*	*$135,031*	*$0*
+ *Approved pass through amounts*	*$0*	$0

17 For 2015-16, reflects actual revenue from DUOS charges as reported in the 2015-16 Annual Reporting RIN, adjusted for unpaid network charges associated with the GoEnergy ROLR event. Further information supporting our adjustment is set out in Attachment 5.

(A minus B) Under/over recovery of revenue for regulatory year	$6,068	$0

<u>DUOS unders and overs account</u>		
Nominal WACC t-2 (per cent)	6.01%	
Nominal WACC t-1 (per cent)	6.04%	
Opening balance	$0	$6,821
Interest on opening balance for 1 regulatory year	$0	n/a
Under/over recovery of revenue for regulatory year	$6,068	($6,821)
Interest on under/over recovery for 2 regulatory years	$753	n/a
Closing balance	$6,821	$0

3.1.2 Revenue allocation

Rule requirement

Clause 6.18.1A (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.

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 into cost reflective tariffs.

Ergon Energy has applied the approach set out in our TSS in establishing 2017-18 tariffs in this Pricing Proposal.

3.1.3 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*.

Ergon Energy notes clause 6.1.4(a) of the NER specifically prohibits DUOS charges being applied for the export of electricity generated by the user into the distribution network. As outlined in Table 2.2 and Chapter 5 of our TSS, 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.

In the case of SACs with micro-generation facilities – these customers are charged 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). That is they will only receive DUOS charges for their use of the network related to electricity import.

3.1.4 Forecast weighted average revenue

Rule requirement

Clause 6.18.2(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 Standard Control Services tariff classes for 2017-18 and 2016-17 is shown in Table 3.2 below.

Table 3.2Table 3.2: Weighted average revenue for Standard Control Services

Tariff class	2016-17	2017-18
ICC – East	$40,662,920	$36,809,039
ICC – West	$13,438,075	$13,239,080
ICC – Mount Isa	$0	$0
CAC – East	$82,606,394	$72,637,253
CAC – West	$12,118,913	$8,399,283
CAC – Mount Isa	$0	$0
EG – East	$2,803,754	$2,497,776
EG – West	$807,251	$710,663
EG – Mount Isa	$0	$0
SAC Large (>100 MWh p.a.) – East	$309,535,613	$292,672,599
SAC Large (>100 MWh p.a.) – West	$81,059,665	$78,309,583
SAC Large (>100 MWh p.a.) – Mount Isa	$4,874,761	$4,486,321
SAC Small (<100 MWh p.a.) – East	$691,642,863	$614,793,022
SAC Small (<100 MWh p.a.) – West	$190,301,116	$181,794,892
SAC Small (<100 MWh p.a.) – Mount Isa	$10,301,214	$9,341,992
SAC Unmetered – East	$18,486,063	$16,424,524
SAC Unmetered – West	$2,678,941	$2,503,229
SAC Unmetered – Mount Isa	$318,858	$277,977

Note: all amounts are GST exclusive

3.1.5 Side constraints

Rule requirement

Clause 6.18.6(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 –The side constraints applying to the price movements of each Ergon Energy tariff class must be consistent with the formula in Figure 14.2

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

The AER provides further guidance on side constraints in Attachment 14 of the Distribution Determination. Ergon Energy must demonstrate that the proposed DUOS prices meet the following side constraints formula:

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

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.

For example, for the 2015–16 year, t–2 is December quarter 2013 and t–1 is December quarter 2014 and in the 2016–17 year, t–2 is December quarter 2014 and t–1 is December quarter 2015 and so on.

X_t is the X factor for each year of the 2015–20 regulatory control period as determined in the PTRM, and annually revised for the return on debt update in accordance with the formula specified in 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. This amount will be deducted from/added to allowed revenue in the 2016–17 pricing proposal.

$B_t^{'}$ 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].

$C_t^{'}$ 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.

Ergon Energy confirms that the weighted average revenue of our tariff classes for 2017-18 is within the percentage allowed by the side constraint formula (i.e. 17.77 per cent). This is demonstrated in Attachment 1.

3.1.6 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*.

Ergon Energy's TSS addresses how our network tariffs satisfy the pricing principles contained in the NER, including stand-alone and avoidable costs.

As noted in our TSS, Ergon Energy interprets these costs in the following manner:

- **Stand-alone costs** for a tariff class are the costs of establishing and maintaining infrastructure to service a single tariff class 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. Therefore, if

Ergon Energy was 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.

Our approach to determining these costs for our Standard Control Services is described in Chapter 6 and Appendix C of our TSS.

In developing the 2017-18 estimates of avoidable costs, expected revenue and stand-alone costs as part of this Pricing Proposal, Ergon Energy has applied calculations consistent with those detailed in Appendix C of our TSS

Table 3.3 below demonstrates that, for each Standard Control Service tariff class containing retail customers, the 2017-18 expected revenue for each tariff class lies on or between the lower bound avoidable cost and an upper bound stand alone cost, in accordance with clause 6.18.5(e) of the NER[18].

The calculation of these amounts is demonstrated in Attachment 1.

Table 3.3: Avoidable costs, expected revenue and stand alone costs for Standard Control Services

Tariff class	Avoidable costs	Expected revenue	Stand alone costs	Clause 6.18.5(e) met
ICC – East	$18,711,385	$36,809,039	$243,999,069	Yes
ICC – West	$1,981,342	$13,239,080	$28,981,777	Yes
ICC – Mount Isa	$0	$0	$0	Yes
CAC – East	$26,061,450	$72,637,253	$264,791,885	Yes
CAC – West	$237,045	$8,399,283	$26,973,909	Yes
CAC – Mount Isa	$0	$0	$0	Yes
SAC Large (>100 MWh p.a.) – East	$181,530,991	$292,672,599	$965,330,345	Yes
SAC Large (>100 MWh p.a.) – West	$50,018,821	$78,309,583	$265,561,202	Yes
SAC Large (>100 MWh p.a.) – Mount Isa	$3,652,262	$4,486,321	$13,062,187	Yes
SAC Small (<100 MWh p.a.) – East	$303,684,965	$614,793,022	$965,330,345	Yes
SAC Small (<100 MWh p.a.) – West	$99,472,513	$181,794,892	$265,561,202	Yes
SAC Small (<100 MWh p.a.) – Mount Isa	$5,953,914	$9,341,992	$13,062,187	Yes
SAC Unmetered – East	$6,806,260	$16,424,524	$560,941,376	Yes
SAC Unmetered – West	$1,872,394	$2,503,229	$26,917,278	Yes
SAC Unmetered – Mount Isa	$92,665	$277,977	$704,551	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.

3.1.7 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 NER formerly required that each tariff and, if it consisted of two or more charging parameters, each charging parameter of a tariff class “take into account” the LRMC for the service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates.

The recent changes to the NER increased the weight placed on LRMC in tariff-setting. The pricing principles in the NER now require each tariff to be “based on” the LRMC of providing the service to the retail customers assigned to that class. 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.

To the extent that tariffs based on the LRMC do not recover the total efficient costs of serving the customers assigned to the tariff, or do not enable us to recover our regulated revenue, we are permitted to apply other tariff components or approaches to meet those requirements. Importantly, any additional tariff components or other approaches to setting tariffs must influence customers’ behaviour as little as possible relative to the behaviour arising under ‘pure’ LRMC tariffs [19].

Both the calculation of LRMC and the application of LRMC to tariff-setting can be undertaken in a number of different ways and the NER does not prescribe the specific approach that DNSPs must take to these matters.

Appendix B of our *Supporting Information - Revised Tariff Structure Statement* explains our LRMC calculation methodology and our approach to incorporating the LRMC in our tariff structures and rates. A useful summary is also provided in Chapter 6 of our TSS.

Application of LRMC in tariff-setting

In our tariff-setting for 2017-18 we have applied the approach to LRMC detailed in our TSS. As noted in our TSS, Ergon Energy’s suite of network tariffs includes:

- ‘legacy tariffs’ or tariff structures that have been in place for many years and which reflect more compromises in respect of the signaling of the LRMC than we consider ideal in the long run
- for all tariff classes except ICC, an alternative optional seasonal time of use demand tariff structure(s) 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.

The application of the LRMC to each of these tariff structures in 2017-18 is summarised below.

[19] NER, clause 6.18.5(g)

Cost reflective tariffs

Consistent with our TSS and clause 6.18.5(h) of the NER, Ergon Energy has considered the impact on retail customers in moving to LRMC-based tariffs, and is progressively applying the appropriate voltage-level LRMC to the peak charging component of each customer class.

The LRMC charges applied to each customer class for 2017-18 and 2016-17 is shown in Table 3.4 below.

Table 3.4: LRMC charges for Standard Control Services

Customer class	Zone	2016-17		2017-18	
		Calculated	Applied	Calculated	Applied
SAC		**$/kW p.a.**			
SAC Small Residential (STOUE & STOUD)	East	376.00	212.00	300.00	228.66
	West	939.00	531.00	751.00	572.41
	Mount Isa	304.00	212.00	304.00	228.58
SAC Small Business (STOUE & STOUD)	East	376.00	212.00	300.00	284.16
	West	939.00	531.00	751.00	711.35
	Mount Isa	304.00	212.00	304.00	284.06
SAC Large (STOUD)	East	300.00	212.00	300.00	168.72
	West	751.00	531.00	751.00	422.36
	Mount Isa	304.00	212.00	304.00	168.66
CAC		**$/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	110.00	132.00	115.50
	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

Legacy tariffs

Efficient application of the LRMC to legacy tariffs is more challenging, given the lack of correlation between the cost of incremental change in demand and the charging parameters within each legacy tariff. Our application of the LRMC to tariff-setting for these tariffs is detailed in Appendix B of our *Supporting Information – Revised Tariff Structure Statement*.[20]

[20] This document is available on our website at: www.ergon.com.au/network/network-management/network-pricing.

3.1.8 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 mimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principles set out in paragraph (f).

The pricing principles in the NER provide that where tariffs based solely on LRMC do not enable Ergon Energy to recover our efficient costs, we may structure our tariffs in order to recover our remaining 'residual' costs. Where this is necessary, tariffs should be set so as to minimise distortions to LRMC-based signals.

Chapter 6 of the TSS addresses how our tariff structures and approach to recovery of residual costs allows Ergon Energy to recover revenue allowances in the least distortionary way, consistent with clause 6.18.5(g) of the NER.

In establishing 2017-18 network tariffs, Ergon Energy confirms that is has been necessary to allocate residual costs, in order to recover the portion of the revenue cap that has not been recovered through LRMC-based tariff parameters. Ergon Energy has used fixed, capacity, off-peak demand and volume parameters to do this. Residual recovery within each customer group has been based on selecting combinations that minimise distortion of the LRMC signal.

In addition, Ergon Energy confirms revenue expected to be recovered from each of our network tariffs will allow Ergon Energy to recover our TAR for Standard Control Services in 2017-18. This is demonstrated in Attachment 1.

3.2 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(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 recover of those charges in the previous *regulatory year*.

3.2.1 Background

Under the NER, Ergon Energy is 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 TUOS charges paid to eligible EGs[21]
- 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:

- charges levied on Ergon Energy for use of the 220 kV network which supplies the Cloncurry network in our Mount Isa Zone[22]
- entry and exit services charged by Powerlink at three connection points – Stoney Creek, Kings Creek and Oakey Town.[23]

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

Consistent with clause 6.18.7(d) of the NER, Ergon Energy confirms our TUOS charges do not include any amounts relating to our revenue cap, jurisdictional schemes or any other amounts recovered from another DNSP.

3.2.2 Revenue allocation

Designated pricing proposal charges paid to TNSPs (Powerlink)[24]

Powerlink charges Ergon Energy at the Transmission Connection Point level.

Their charges have four components:

- Entry/Exit Connection Price ($/month)

[21] 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

[22] Treated as an inter-distributor payment for the purposes of the TUOS unders and overs account.

[23] 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.

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

- 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).

Our network tariff calculation process allocates these 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*.

These charges are then apportioned by Ergon Energy 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[25] (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.[26]

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.

Avoided TUOS

Where Ergon Energy is liable to pay an Avoided TUOS payment to an EG in accordance with clause 5.5(h) and (i) of the NER[27], the payment amount is recovered as part of the TUOS volume charges passed through to customers at the same connection point as the EG.

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25 Also referred to as back-up supply.
26 This is also the case for the DUOS capacity charge.
27 Further information on how Ergon Energy determines Avoided TUOS payments under 5.5(h) and (i) of the NER is 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

Payments to other DNSPs

In the Toowoomba area, Ergon Energy takes 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, Ergon Energy is 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 TUOS charges, using an allocation method similar to that applied to Powerlink charges in the other TUOS Regions.

3.2.3 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

Ergon Energy ensures that any difference between revenue recovered from customers from TUOS charges and the actual transmission-related costs paid by Ergon Energy is offset by an annual unders and overs process. Under these arrangements there is a two year lag between the year in which the under or over recovery occurs and the year in which the adjustment to the expected TUOS revenue to be recovered is made.

Table 3.5 below sets out Ergon Energy's 2015-16 over recovery based on information lodged (and audited) in our 2015-16 Annual Reporting Regulatory Information Notice (RIN). Consistent with our proposed treatment of the GoEnergy ROLR event in the DUOS unders and overs account, Ergon Energy is proposing an adjustment to actual 2015-16 TUOS revenue to remove unpaid network charges associated with the event. This is subject to approval by the AER as part of this Pricing Proposal.

This table satisfies the requirements of Attachment 14 of the Distribution Determination and hence clause 6.18.7 of the NER. Attachment 1 sets out the calculation of the TUOS unders and overs account, including the proposed 2017-18 adjustments.

Table 3.5: Calculation of TUOS unders and overs account

	2015-16 Year t-2 (actual) $'000	2017-18 Year t (forecast) $'000
(A) Revenue from designated pricing proposal charges (DPPC) [28]	$370,103	$263,951
(B) Less DPPC related payments for regulatory year =	$359,179	$263,951
+ DPPC charges to be paid to TNSP	$347,581	$270,261
+ Avoided TUOS payments	$2,072	$1,962
+ Inter–distributor payments	$6,294	$4,008
+ DPPC revenue under/over recovery approved	$3,232	($12,280)
(A minus B) Under/over recovery of revenue for regulatory year	$10,924	$0
<u>DPPC unders and overs account</u>		
Nominal WACC t-2 (per cent)	6.01%	
Nominal WACC t-1 (per cent)	6.04%	
Opening balance	$0	$12,280
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	$10,924	($12,280)
Interest on under/over recovery for 2 regulatory years	$1,356	n/a
Closing balance	$12,280	$0

[28] For 2015-16, reflects actual revenue from TUOS charges as reported in the 2015-16 Annual Reporting RIN, adjusted for unpaid network charges associated with the GoEnergy ROLR event. Further information supporting our adjustment is set out in Attachment 5

3.3 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*.

3.3.1 Background

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

- schemes set out explicitly under clause 6.18.7A(e) of the NER. For Queensland, this currently includes the Solar Bonus Scheme, which obligates Ergon Energy to pay a FiT for energy supplied into our distribution network from specific micro-embedded generators.[29]
- those schemes determined by the AER to be jurisdictional schemes under clause 6.18.7A(l) of the NER. For Queensland, this currently includes the energy industry levy. Ergon Energy is obligated under our Distribution Authority to pay a proportion of the Queensland Government's funding commitments for the AEMC in relation to this levy.

Our Pricing Proposal must set out how jurisdictional scheme amounts (i.e. the amount(s) we are obligated to pay under the scheme) for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from the over or under recovery of those amounts.[30]

3.3.2 Jurisdictional scheme eligibility

The last jurisdictional scheme approval date for the Solar Bonus Scheme was 21 May 2015 (i.e. the date we submitted our 2015–16 Pricing Proposal to the AER). Since that time, the jurisdictional scheme has not been amended.

The energy industry levy was approved on 22 April 2016. There have been no changes since this approval date.

3.3.3 Revenue allocation

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

[29] The scheme operates under clause 44A of the *Electricity Act 1994 (Qld).*
[30] NER, clause 6.18.2(b)(6A).

Consistent with our approach in 2016-17, revenue in respect of jurisdictional scheme amounts has been allocated to tariff classes using an allocation process that is similar to how overhead costs incorporated in DUOS charges are allocated.

The total revenue requirement for each tariff class is then converted into tariffs made up of a:

- fixed charge ($/day) and a volume charge ($/kWh) for SACs[31] and CACs
- fixed charge ($/day) for ICCs.

Jurisdictional scheme charges apply to all network tariffs, except unmetered supply and EGs.

3.3.4 Jurisdictional scheme unders and over account

Rule requirement

Clause 6.18.7 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 report to us its jurisdictional scheme amounts recovery in accordance with appendix C of this attachment.

Similar to the treatment of TUOS charges, there is an annual unders and overs process to account for differences between revenue recovered from customers from jurisdictional scheme charges and the actual jurisdictional scheme costs paid by Ergon Energy. Under these arrangements there is a two year lag between the year in which the under or over recovery occurs and the year in which the adjustment to the expected jurisdictional revenue to be recovered is made.

Table 3.6 below sets out Ergon Energy's 2015-16 over recovery based on information lodged (and audited) in our 2015-16 Annual Reporting Regulatory Information Notice (RIN). Consistent with our proposed treatment of the GoEnergy ROLR event in the DUOS and TUOS unders and overs account, Ergon Energy is proposing an adjustment to actual 2015-16 jurisdictional scheme revenue to remove unpaid network charges associated with the event. This is subject to approval by the AER as part of this Pricing Proposal.

Attachment 1 sets out the calculation of the jurisdictional scheme unders and overs account.

[31] A fixed charge does not apply to controlled load tariffs.

Table 3.6: Calculation of jurisdictional scheme unders and overs account

	2015-16 Year t-2 (Actual) $'000	2017-18 Year t (Forecast) $'000
(A) Revenue from jurisdictional schemes[32]	$114,136	$92,264
(B) Less jurisdictional scheme payments for regulatory year =	$109,122	$97,901
+ Jurisdictional scheme payments (Solar Bonus Scheme)	$109,045	$97,815
+ Jurisdictional scheme payments (Energy industry levy)	$77	$86
+ Jurisdictional scheme amounts revenue under/over recovery approved	$0	n/a
(A minus B) Under/over recovery of revenue for regulatory year	$5,014	($5,637)
Jurisdictional scheme amount unders and overs account		
Nominal WACC t-2 (per cent)	6.01%	
Nominal WACC t-1 (per cent)	6.04%	
Opening balance	$0	$5,637
Interest on opening balance for 1 regulatory year	$0	n/a
Under/over recovery of revenue for regulatory year	$5,014	($5,637)
Interest on under/over recovery for 2 regulatory years	$622	n/a
Closing balance	$5,637	$0

3.4 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

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

Ergon Energy annually prepares a forecast of customer numbers, demand and energy consumption for preparation of our Pricing Proposal. This forecast is done by network user group, with an initial forecast generally prepared in October of each year. This is later refined, typically in January and/or February of the

32 For 2015-16, reflects actual revenue from Jurisdictional Scheme charges as reported in the 2015-16 Annual Reporting RIN, adjusted for unpaid network charges associated with the GoEnergy ROLR event. Further information supporting our adjustment is set out in Attachment 5.

following year, based on the most up to date information available prior to preparation of the annual Pricing Proposal.

A summary of the forecasts used for developing the 2017-18 prices are set out in Attachment 1 of this Pricing Proposal.

Our forecasts are subject to significant uncertainties with regard to future volumes, including state government initiatives which may increase the uptake of renewable energy.

3.4.1 Major customer forecast (ICCs, CACs and EGs)

Major customers are forecast individually for energy consumption and maximum any-time demand. The energy forecast is based on a review of each customer's recent actual consumption history plus any confirmed future operational changes. The forecast for EGs is the amount of energy generated into Ergon Energy's distribution system. For ICCs and CACs, it is energy consumption that is being forecast.

The forecast demand for major customers is either:

- negotiated with the network user and detailed in their connection contract ('contracted demand')
- based on a review of actual demand history, with adjustments made for confirmed additions and losses of load.

CACs demand forecasts are also completed at a forecast monthly demand level based on historical consumption pattern. For new customers a flat usage or similar industry load profile is applied as appropriate until historical data for their connection is available.

3.4.2 SAC group forecast

For the SAC network user group, forecast energy consumption, demand and customer numbers are first prepared at the customer group level. The customer groups are:

- SAC Large
- SAC Small
  - Residential
  - Business
  - Controlled Load
- SAC Unmetered.

Forecast energy consumption and customer numbers are based on a combination of econometric forecasts and trend extrapolation. When the energy forecast for a customer group is performed using an econometric model, the forecast is done on a quarterly basis to capture the impact of the potential seasonality of the drivers. The quarterly outcome is then summed to the annual level for network pricing modelling.

The econometric forecasts for each customer group were developed by fitting econometric equations to historical data. The independent variables/drivers are selected based on a combination of fundamental economic theory as well as the statistical significance and appropriateness of sign and magnitude of the corresponding estimated coefficients. These econometric models will be reviewed and re-tested from time to time when more observations become available.

Demand is not measured or forecast for SACs, but customer group demands are calculated using appropriate load factors which are then used as allocators in the DCOS Model.

Once the customer group level forecasts have been established, Ergon Energy then disaggregates the forecasts into individual tariffs for network pricing modelling.

A further description of the forecasting approach by each customer group is set out below.

SAC Large

For SAC Large, customer number forecasts are based on trend extrapolation using historical data. Total energy for SAC Large is forecast directly using econometric principles, with forecast levels determined by:

- historical consumption
- historical and forecast Gross Regional Product (GRP)
- historical and forecast retail prices[33]

The estimated relationship between energy and the variables incorporated in the econometric model is consistent with common expectation: higher GRP has a positive impact on energy consumption and higher retail prices have a negative impact on energy consumption.

SAC Small

For SAC Small, customer number forecasts are based on trend extrapolation using historical data. Forecast energy for SAC Small is based on econometric principles, however the approach differs by network tariff category:

- Residential – energy is forecast per customer, and then multiplied by forecast customer numbers. Forecast energy per customer is determined by:
  - historical consumption, adjusted to estimate when consumption physically takes place[34]
  - historical and forecast retail prices
- Business – energy for this network tariff category is forecast directly (rather than per customer). Forecast energy is determined by:
  - historical consumption, adjusted to estimate when consumption physically takes place
  - historical and forecast Gross Regional Product (GRP)
  - historical and forecast retail prices

The estimated relationship between energy and the variables incorporated in the econometric model is consistent with common expectation: Higher GRP has a positive impact on energy consumption and higher retail prices have a negative impact on energy consumption.

Controlled load and unmetered supplies

Both the customer number and energy forecast for controlled load and unmetered customers are based on trend extrapolation. This is because there is historically less variability in controlled load and unmetered consumption and economic variables are less likely to be impacted by the level of consumption.

3.4.3 TUOS forecasts

Annual TUOS payments are made to Powerlink, other DNSPs, and EGs for Avoided TUOS. The forecast of annual TUOS payments to Powerlink is based on preliminary TUOS prices provided by Powerlink in March 2017. Forecast energy, historical energy and nominated demand are applied to the TUOS prices to give forecast TUOS payments for each Transmission Connection Point:

[33] Based on AEMO, QCA notified prices and SAC sample data
[34] Ergon Energy's historical billing data records energy at the time the bill was issued. As a large portion of SAC small customers are on quarterly billing cycles, adjustments are necessary to estimate when consumption physically takes place

- The energy forecast is prepared for each Transmission Connection Point, considering the impact of embedded generation, major customers supplied, and an extrapolation of the historical remaining General Cost Pool customer group. Adjustments for Distribution Loss Factors (DLFs) are taken into account where energy sales forecasts are used as the basis for the purchase forecast.
- The Powerlink nominated demand is the average of the ten highest daily demands between November and March each year at each Transmission Connection Point. This is forecast by applying the historical load factor to the forecast energy for each Transmission Connection Point.

Similarly, forecast TUOS payments to other DNSPs are based on rates provided by the DNSP and forecast energy and demand applicable to that supply. These energy and demand forecasts are provided by Ergon Energy to the DNSP for use in setting their network charges and are based on an extrapolation of historical data, while considering other known changes to the connection arrangement.

Forecast Avoided TUOS payments are based on the relevant EG's forecast export used within the Ergon Energy distribution network and the relevant transmission locational energy charge. The forecast export is based on historical demand, while considering the impact of confirmed new EG projects.

3.5 Proposed prices

The proposed tariffs to be adopted for our Standard Control Services in 2017-18 are set out in Appendix 1 of this Pricing Proposal.

Section 5.4 provides further explanation on the differences between our proposed 2017-18 tariffs and the corresponding indicative pricing levels set out in our TSS.

4 Alternative Control Services

4.1 Tariff classes and tariffs

As outlined in Section 2.1, clause 6.18.2(b)(1) of the NER requires a Pricing Proposal to set out the proposed tariffs for each tariff class as specified in Ergon Energy's TSS. In addition, the Pricing Proposal must set out for each proposed tariff, the charging parameters and elements of service to which each charging parameter relates to meet clause 6.18.2(b)(3) of the NER.

Chapter 10 of Ergon Energy's TSS details our Alternative Control Services tariff classes and their respective tariff structures, including the charging parameters that apply in 2017-18 to 2019-20.

As noted in our TSS, Ergon Energy's tariff classes for Alternative Control Services are differentiated at the highest level according to the AER's classification of services and the basis of pricing approved by the AER.

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

The consequent tariff classes under this approach 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

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). This is because Alternative Control Services are a subset of Direct Control Services and all of Ergon Energy's customers are assigned to at least one network tariff and one Standard Control Service tariff class. Further, clause 6.18.3(c) of the NER is met by Ergon Energy distinguishing between the tariff classes for Standard Control Services and for Alternative Control Services.

Finally, clause 6.18.3(d) of the NER requires that a tariff class be constituted with regard to the need to group customers together on an economically efficient basis, and the need to avoid unnecessary transaction costs. As noted in Section 2.1, this clause requires a balance to be struck between setting tariffs that send efficient signals to individual customers while minimising the costs of developing and implementing a large number of bespoke tariffs.

Ergon Energy's tariffs for Alternative Control Services are grouped according to the classification and basis of pricing determined by the AER in its 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, 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 2017-18 Alternative Control Services tariffs is shown in Table 4.2 below and Appendix 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 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 ($) per day per meter. Within the tariff structure, metering service charges differ by: – the type of metering service (primary, controlled load, embedded generation); and – the type of cost recovery (capital, non-capital) For call outs associated with Default Metering Services[35] - a fixed rate ($) 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[36]. 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.

[35] 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.
[36] Except where the proposed LED transition program is being implemented

Tariffs by Tariff Class

In accordance with Clause 6.18.2(b)(2) of the NER, each of Ergon Energy's Alternative Control Services tariffs for 2017-18 are set out in Appendix 1.

Chapter 11 of our TSS contains a description of the process we undertake each year to establish tariffs for Alternative Control Services. Ergon Energy has applied this approach in establishing the proposed 2017-18 Alternative Control Services tariffs set out in this Pricing Proposal.

4.2 Tariff assignment policies

As noted in Section 0, clause 6.18.1A(a)(2) of the NER requires our TSS to outline the policies and procedures Ergon Energy applies for assigning customers to tariffs classes and tariffs. Similar to our approach for Standard Control Services, Ergon Energy has 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. Ergon Energy will comply with these procedures in 2017-18.

As highlighted in Section 0, 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, Ergon Energy considers the charging parameters of our Alternative Control Service tariffs do not vary according to the usage or load profile of a customer (as it does for Standard Control Services). Therefore, Ergon Energy considers that this requirement does not apply to our Alternative Control Services. Consequently, Ergon Energy does not need to assess or review the basis (the approved formulae and price caps) on which a customer is charged for Alternative Control Services.

4.3 Control mechanism

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

Chapter 11 of our TSS sets out the process we undertake 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.[37]

[37] 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.

The calculation of Ergon Energy's Alternative Control Service prices, including our compliance with the price cap control mechanism, is provided in Attachment 4. Various cost inputs used in the calculation of our fee based and quoted services have been updated. These changes are discussed below.

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, with quantitative information available in Attachment 4.

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 4.3.

Table 4.3: 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

Ergon Energy has adjusted the nominal labour, fleet, materials and contractor services escalators by annual CPI data to December quarter 2016 as published by the ABS.

Labour on costs

Ergon Energy has applied the same labour on cost rates for both ordinary time hours and overtime hours in comparison to those used in 2016-17 (43.5 per cent and 6 per cent respectively).

Materials on costs

The materials (stores) on cost rate in 2017-18 will remain at 16.6 per cent, consistent with the rate calculated and applied in 2016-17.

Overhead rates

Ergon Energy has recalculated the overhead rates.[38] Consistent with our AER-approved Cost Allocation Method (CAM),[39] Ergon Energy uses the following methodology to calculate the overhead rates for our fee based services (cost build-up only) and quoted services:

1. **Determine total shared costs (overheads) for the regulatory year**. Budget data is used to set costs expected to relate to shared 'support' services which cannot be directly attributable to a particular activity or work plan. For example, shared costs include costs associated with business units that provide corporate support services across the Ergon Energy Group (Corporate Overheads). Shared costs also include costs associated with support services provided within Ergon Energy's operational business units that have not been directly attributed (Operational Overheads). Operational Overheads predominantly represent labour and administration costs associated with (but not limited to) senior management, technical and operations support, including maintenance and construction standards, mapping, technical data records and field investigations and auditing.
2. **Allocation of total shared costs (overheads) between Ergon Energy Group districts and Ergon Energy Corporation Limited Line Of Business (LOB)**. Ergon Energy Corporation Limited, as the parent entity of the Ergon Energy Group, provides 'support' services to a number of other districts (or legal entities) and LOB within Ergon Energy Corporation Limited. These include:
    - *Ergon Energy Queensland Pty Ltd (EEQ)* – a subsidiary entity responsible for providing non-competing electricity retail services to non-market customers
    - *Ergon Energy Telecommunications Pty Ltd* – a subsidiary entity and licensed telecommunications carrier providing wholesale high-speed data capacity to the Ergon Energy Group and external customers
    - *SPARQ Solutions Pty Ltd (SPARQ)* – a joint venture company formed by Ergon Energy and Energex providing information technology and telecommunications to Ergon Energy and Energex. Ergon Energy holds a 50 per cent share in SPARQ
    - *Ergon Energy Corporation Limited LOBs* – the parent entity is broken down over various LOB – Regulated, Non-Regulated, Isolated System, External, Powerlink and Workshop Services.

    Once the districts and total shared costs for the regulatory year are determined, the costs are then allocated to each entity in the Ergon Energy Group using causal allocators in accordance with the CAM and in some instances using a commercial agreement between Ergon Energy and SPARQ. The choice of allocator depends on the type of service provided. For example, where the shared costs are identified as relating solely to a legal entity within the Ergon Energy Group, costs are directly allocated to that entity. In other cases, the number of transactions undertaken or time spent in providing the service may be the driver to calculate the allocation of work and shared costs to each entity.
3. **Determine the direct costs for the regulated LOB.** Budget data is used to set costs expected to be directly attributable to regulated operating expenditure (opex) and capital expenditure (capex) required for delivering our work plans. These costs are determined using an Activity Based Costing Method which maps and directly attributes expected costs of particular activities to the Chart of Accounts.
4. **Allocation of shared (support) costs between regulated opex and capex activities**. For the pool of shared (support) costs that have been allocated to the regulated distribution services

[38] Ergon Energy has not updated the overhead rate applying to the administration labour rate. Consistent with the Distribution Determination, we have applied the AER's maximum overhead rate.
[39] As approved on 15 August 2014. Available at http://www.aer.gov.au/node/27108.

provided by Ergon Energy Corporation Limited, the next step is to allocate these shared (support) costs between regulated opex activities and regulated capex activities.

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

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

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

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

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

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

   For example, the regulated capex overhead rate applies to customer services capital work and the customer services opex overhead rate applies to customer services operational work. Rearrangement of Network Assets work can either be classified as capex or opex depending on the extent to which the network is modified, for substantial rearrangement, relocation and/or rebuilds the regulated capex rate would apply.

Ergon Energy's 2017-18 overhead rate calculation is provided in Attachment 4.

4.5 Compliance with pricing principles

4.5.1 Avoidable and stand-alone costs

As noted in Section 3.1.6, 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 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 2017-18.

4.5.2 Long Run Marginal Cost

As highlighted in Section 0, the NER now 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 set out in clause 6.18.5(f) of the NER.

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.

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

4.5.3 Recovery of residual costs

As discussed in Section 3.1.8, 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.

Ergon Energy notes 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).

4.6 Proposed prices

Appendix 1 sets out the 2017-18 tariffs for our Alternative Control Services. In relation to each quoted service, it is important to note that the prices provided in Appendix 1 are examples only. This is because the actual prices for quoted services will be determined at the time of the requestor’s enquiry and will reflect the actual requirements of the service being requested.

5 Other compliance

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.

Ergon Energy has been very 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.

As noted in Section 0, Ergon Energy is transitioning to LRMC-based tariffs progressively, while continuing to offer a number of legacy tariffs.

LRMC pricing principles embody a two part tariff outcome. The first part promulgates the LRMC price signal while the second part addresses 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 as possible and aligned with enabling customer responses that support optimal use (or not) of the network.

In establishing and populating the parameters to recover residual revenue, Ergon Energy has targeted minimising any distortionary impact of the non-LRMC-based parameters on customer response to the LRMC signals (refer Section 3.1.8).

Therefore, Ergon Energy's tariffs have been established with a view to developing LRMC tariff parameters that customers are likely and able to respond to, while choosing and calibrating residual recovery parameters that are less likely to distort the LRMC signals 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. Therefore, customers now have more choice and control in how they are charged for their use of the network and can make their own informed decisions on which tariff they prefer.

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:
  - Deliberately moving progressively to fully incorporate the 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 relatively attractive to a large number of customers who have the choice to move, or to stay on less efficient default tariffs.

In establishing the 2017-18 tariffs, Ergon Energy has continued to apply these measures.

It is important to note that the extent to which these network signals are 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 2017-18.

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 Limited (Energex).

This affects customers’ ability to respond to our network price signals.

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 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.

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, Ergon Energy believes adjustments to Alternative Control Services tariffs to satisfy clause 6.18.5(h) are not necessary.

5.1.2 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*.

Ergon Energy's TSS addresses how our tariffs and tariff structures for Standard and Alternative Control Services satisfy this pricing principle. Our stakeholder engagement has played a key role in shaping our network tariff structures and informing the development of our TSS.

Ergon Energy considers that our tariffs strike the right balance between cost reflectivity and being as simple and easy to understand as possible. Still, our stakeholder engagement delivered a strong message of the need for the introduction of these tariffs to be accompanied by customer information, advice and education to allow customer to effectively respond to the new choices that are being presented to them.

We expect this transition will take time and in the short term will continue to inform customers through our various channels.

Further information on our stakeholder engagement is set out in our *Supporting Information - Revised Tariff Structure Statement* document.

5.1.3 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)

Network tariff adjustments

As noted in Section 5.1.1, Ergon Energy has considered the impact on customers of changes to tariffs between regulatory years, and has adjusted 2017-18 network tariffs on the following basis:

- Setting some tariffs at variance from the full LRMC values for both our legacy and optional tariffs (refer to Section 0)
- Selecting a combination of charges to recover Ergon Energy's 2017-18 residual revenue to support minimising distortion of the LRMC signal (refer to Section 3.1.8).

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

As highlighted in Section 5.1.2, 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. Ergon Energy has not made any adjustments to our tariffs in 2017-18 on the basis of this principle.

Finally, clause 6.18.5(j) of the NER requires tariffs to comply with the Rules and all applicable regulatory instruments. Ergon Energy confirms that our 2017-18 network tariffs have been developed to be compliant with the NER and the AER's Distribution Determination. Ergon Energy has 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.

Alternative Control Service adjustments

As noted in Section 5.1.1 Ergon Energy has 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, Ergon Energy makes 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 2017-18, may be lower than the prices contained in Appendix 1. Once published for the 2017-18 regulatory year, the *Price List for Alternative Control Services* will provide the rates applicable for 2017-18 as a result of Schedule 8 maximum price caps, and hence the prices customers will be charged.

5.2 Adjustments to tariffs within a regulatory year

Rule requirement

Clause 6.18.2(b)(5) A *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.

5.2.1 Network Tariff adjustments within 2017-18

Variations or adjustments to tariffs will occur where an ICC, CAC or EG advises Ergon Energy that they intend to alter their demand or connection characteristics during 2017-18. In this case, Ergon Energy will recalculate the charging parameters of the tariff (noting that the published rates will continue to apply to CACs). New tariffs will be created for each ICC and EG that connects during 2017-18, in line with the methodology set out in this Pricing Proposal.

During 2017-18, Ergon Energy may also be required to calculate additional tariffs and/or prices for existing services which we have not provided prices for in this Pricing Proposal. This may occur because of a new customer connection 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.[40]

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

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

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

5.2.2 Alternative Control Service adjustments within 2017-18

In November 2015, the Australian Energy Market Commission (AEMC) finalised its *Competition in Metering and Related Services* rule change (the 'Power of Choice' rule change). The new arrangement will create a fundamental transformation of the energy sector. The key gateway to customers and the provision of new energy services – the meter – will be opened to more competition, particularly in relation to small customers. As a result, alternative providers will be responsible for the installation and delivery of most metering services. It should be noted that Ergon Energy will remain responsible for the maintenance of its existing fleet of Type 5 and 6 meters.

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

As a consequence of the new 'Power of Choice' rule change coming into effect on the 1 December 2017, Ergon Energy is anticipating that a number of prices for our existing Alternative Control Services will need to be recalculated during 2017-18. In the main, the revised Alternative Control Services charges are required to remove the metering component that will be subject to contestability. Ergon Energy has also identified a very limited number of services whereby Ergon Energy may need to reallocate costs, and levy user-specific charges on the appropriate party from 1 December 2017 (i.e. retailers or Metering Providers).

It is important to note, that no new Alternative Control Services are proposed to be created by Ergon Energy. However in some circumstances, some Alternative Control Services may need to be disaggregated to allow for component charging (e.g. where Ergon Energy or an alternative provider can provide the metering component of the relevant service).

In any case, the revised Alternative Control Services charges will be less than the price for the 'fully-inclusive' service approved by the AER as part of the 2017-18 Pricing Proposal process.

Once the revised prices have been developed, Ergon Energy will provide the information to the AER and publish an updated *Price List for Alternative Control Services*. Stakeholders will also be notified of the changes consistent with established processes and protocols for such changes.

Further detail on the Alternative Control Services which are expected to be amended in December 2017 is set out in Table 5.1 below.

Table 5.1: Alternative Control Services to be adjusted for Power of Choice changes

Service	Proposed Changes (from 1 December 2017)
Fee based services	
Temporary connection, not in permanent position - single phase metered - urban/short rural feeders	○ Charges to be amended to remove and/or disaggregate metering component previously only performed by Ergon Energy
Temporary connection, not in permanent position - single phase metered - long rural/isolated feeders	
Temporary connection, not in permanent position - multi phase metered - urban/short rural feeders	
Temporary connection, not in permanent position - multi phase metered - long rural/isolated feeders	
Supply abolishment during business hours - urban/short rural feeders	○ Charges to be amended to remove and/or disaggregate metering component previously only performed by Ergon Energy
Supply abolishment during business hours - long rural/isolated feeders	
Install new or replacement meter (Type 5 and 6) - Single phase - urban/short rural feeder	○ Service will cease to be offered[41].
Install new or replacement meter (Type 5 and 6) - Single phase - long rural/isolated feeder	
Install new or replacement meter (Type 5 and 6) - Dual element - urban/short rural feeder	
Install new or replacement meter (Type 5 and 6) - Dual element - long rural/isolated feeder	

[41] Ergon Energy is still considering the arrangements for new and replacement metering in our Mount Isa-Cloncurry and Isolated supply networks. This is on the basis that the Power of Choice changes do not apply, as the supply networks are not connected to the national grid and therefore not subject to Chapter 7 of the NER. Ergon Energy will also continue to maintain its existing fleet of Type 5 and 6 meters, including distributor initiated replacements.

Service	Proposed Changes (from 1 December 2017)
Install new or replacement meter (Type 5 and 6) - Polyphase - urban/short rural feeder	
Install new or replacement meter (Type 5 and 6) - Polyphase - long rural/isolated feeder	
Install new or replacement meter (CT) - urban/short rural feeder	
Install new or replacement meter (CT) - long rural/isolated feeder	
Quoted Services	
Customer or retailer requested appointments	Service description expanded to allow charges to be levied on retailers or metering providers, where: ○ Ergon Energy is requested to isolate power to facilitate a meter installation undertaken by another party. Prior to the Power of Choice, these costs were factored into upfront meter charges paid for by customers. ○ Ergon Energy attends to restore a loss of supply due to a fault with the metering provider's installation
Other quoted services including metering related components (various)	Appropriate adjustments will be made to the quoted price at the time of the customer's enquiry to remove any metering related components that will no longer be performed by Ergon Energy.

Other than the Power of Choice changes, there are no other variations or adjustments proposed to be made to Alternative Control Services tariffs during the course of the regulatory year[42].

5.3 Changes between regulatory years

Rule requirement

Clause 6.18.2(b)8) A *pricing proposal* must 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.

This Pricing Proposal contains several changes since 2016-17. These changes are also largely reflected in our TSS.

5.3.1 Network tariff changes

As noted in Section 1.5, Ergon Energy is proposing a number of changes to our network tariffs for Standard Control Services from 1 July 2017. These changes are described in more detail in the remainder of this section and have been reflected in Appendix 1.

Changes to ICC network tariffs

Consistent with our TSS, no changes are proposed to ICC tariffs in 2017-18.

[42] The exception being the maximum price caps under Schedule 8 of the *Electricity Regulation 2006,* discussed in Section 1.4.4 of this Pricing Proposal

Changes to CAC network tariffs

Introduction of excess kVAr charges

Ergon Energy initially proposed to introduce excess kVAr charges for CACs in 2016-17 following extensive consultation with customers, retailers and other stakeholders. However in May 2016, a decision was made to defer the introduction of the charge until after approval of our TSS.

Consistent with intentions noted in our TSS, Ergon Energy is proceeding with the introduction of an excess kVAr charge for CACs from 1 July 2017. The charge will reinforce the price signal introduced by the kVA tariff in 2015-16 and encourage customer to improve their sites' power factor and reduce the network capacity they require.

The ratio of real power (kW) to actual power (kVA) is known as the power factor. A customer's power factor and demand as measured in kVA is important because distribution systems must be designed to supply the actual power required. A low power factor suggests the quantity of actual power delivered to a customer may be able to be reduced. It is more often the case that the cost for the customer to take action to improve power factor is less than the cost of the additional network capacity required if no action is taken. Signalling the cost of power factor correction to customers provides them the opportunity to make a commercial investment in efficient power factor improvement.

The excess kVAr charge for CACs will replicate the charge currently applied to ICCs. A customer's kVAr is calculated monthly based on the power factor recorded at the time of their individual monthly kVA peak. To the extent the customer's actual kVAr exceeds their permissible kVAr quantity (determined by the customer's authorised demand and the NER compliant power factor), excess kVAr charges are applied.

Our TSS and Appendix C of our *Supporting Information - Revised Tariff Structure Statement* sets out additional information on our excess kVAr charges, including details of our consultation with CACs.

Change in default tariff for CACs

Consistent with our approach for SAC Large customers (refer below), and as foreshadowed in our TSS, Ergon Energy is proposing that, from 1 March 2018[43], any new CAC premise connections will 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.

Changes to EG network tariffs

Standardised rates for EG tariffs

Consistent with our TSS, Ergon Energy is considering introducing standardised rates for EG tariffs if the volume of new connections makes it impractical for Ergon Energy to continue site-specific pricing.

Ergon Energy does not intend to introduce standardised rates for EGs in 2017-18. However Ergon Energy will continue to monitor this during 2017-18, and to the extent necessary, develop standardised rates for future Pricing Proposals (2018-20).

[43] Due to operational complexities associated with implementing this business rule prior to the Power of Choice changes, Ergon Energy has decided not to implement the change until after the 1 December 2017. The (further delayed) 1 March 2018 timeframe will also help mitigate the risk of customers having a poor initial experience with the STOUD tariff, by otherwise immediately incurring peak summer charges.

Changes to SAC Large network tariffs

Change in default tariff for SAC Large

The new seasonal time-of-use demand (STOUD) tariff, introduced for SAC Large customers in July 2015 has been well received and taken up by customers. This option has come about from our work to better understand our cost drivers and make our tariffs more cost reflective. Unlike the other demand tariffs available for this group, this tariff recognises the peak demand window that occurs in the summer months. The TSS, made provision for any new premises, and customers moving into existing premises (with the required metering) from 1 July 2017 to be assigned to the STOUD tariff. From 1 March 2018[44], any new SAC Large premise connections will 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.

Retirement of SAC Large demand high voltage tariffs

Consistent with intentions noted in our 2016-17 Pricing Proposal and the TSS Ergon Energy is continuing to phase out Demand High Voltage tariffs. From 1 July 2017 this tariff will no longer be available in the East Zone[45]. Existing premises will be reassigned to either the STOUD tariff or one of the SAC Large general anytime demand tariffs. Ergon Energy notes, that there are currently only 10 customers assigned to the SAC Large Demand High Voltage tariffs. Ergon Energy has undertaken a customer impact assessment which indicates all customers will be better off, or on par with the level of network charges expected to be paid during 2016-17, following their reassignment. This is based on applying the 2016-17 tariff and the proposed alternative 2017-18 tariff to the latest load information available for the customer (1 March 2016 to 28 February 2017).

5.3.2 Alternative Control Services changes

As noted in Section 1.5, Ergon Energy is proposing a number of amendments to our Alternative Control Services for 2017-18. These changes are detailed below.

Power of Choice changes

As noted in Section 5.2.2, as a consequence of the Power of Choice rule change, a number of Ergon Energy's Alternative Control Services will be affected during the 2017-18 regulatory year. Further detail on the Power of Choice changes and the proposed mechanism to calculate the revised charges in December 2017 is set out in Section 5.2.2.

Other Alternative Control Services changes

In addition to the changes outlined above, we have made a number of minor amendments to our Alternative Control Services since 2016–17. These changes are detailed in Table 5.2 below.

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[44] Due to operational complexities associated with implementing this business rule prior to the Power of Choice changes, Ergon Energy has decided not to implement the change until after the 1 December 2017. The (further delayed) 1 March 2018 timeframe will also help mitigate the risk of customers having a poor initial experience with the STOUD tariff, by otherwise immediately incurring peak summer charges.

[45] Demand high voltage tariffs were phased out of the West and Mount Isa Zones in 2016-17.

Table 5.2: Summary of other Alternative Control Services changes since 2016-17

Service	Changes
Fee based services	
Supply abolishment	○ Amended to clarify metering only to be removed when present. We note that in some circumstances, decommissioning of a meter is not required (e.g. supply abolishment for an unmetered connection). We also note that the price of this service is to be recalculated during 2017-18 as a result of Power of Choice changes. Ergon Energy intends to clarify at this time that the lower price (i.e. excluding the metering component) would also apply for an unmetered connection.
Quoted Services	
Assessment of parallel generator applications	○ Amended to clarify this service is intended to apply to non-exporting generator applications. In some cases a 'parallel generator' may export into the distribution system, so this reference has been removed. The term 'parallel generation agreement' has also been updated to 'consent agreement' to align with current business practice.
Default metering services	
Annual metering charges – embedded generation (capital and non-capital)	○ Removed reference to 'parallel generators', to clarify the exception is intended to apply to any embedded generating unit that does not require the installation of a new meter or the reconfiguration of an existing meter.

5.3.3 Other changes compared to 2016–17 Pricing Proposal

In addition to the above changes, Ergon Energy has made a number of amendments to the 2017-18 Pricing Proposal. These include:

- updates to align with the new NER provisions outlined in clause 6.18 of the NER. The new pricing principles and our approved TSS will apply to Ergon Energy for the first time in 2017-18.[46]
- refining the methodology used to forecast SAC customer numbers and energy consumption. SAC forecasts underpinning our 2017-18 prices are now based on a combination of econometric forecasts and trend extrapolation (refer to Section 3.4). Previously our SAC forecasts were based on extrapolations of historical data.
- refining our approach to developing indicative prices (as set out in Attachment 2). These refinements essentially provide Ergon Energy with more flexibility to adjust inputs and re-model specific future year rates (rather than applying high level assumptions to escalate base year rates).

5.4 Difference between proposed prices and relevant indicative prices

Rule requirement

Clause 6.18.2(b)(7A) A *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.

Ergon Energy notes that the NER only require us to provide (and explain material differences) for our Direct Control Services (i.e. Standard Control Services (DUOS) and Alternative Control Services). However, our

[46] Relates to changes associated with the AEMC's *Distribution Network Pricing Arrangements* rule change. The new rules did not apply to Ergon Energy's 2016-17 Pricing Proposal due to transitional arrangements

indicative pricing schedule provides indicative prices for TUOS and jurisdictional scheme charges too. On this basis, we have focused our explanation on the differences in our DUOS and Alternative Control Services prices, whilst including high level commentary on differences between TUOS and jurisdictional scheme charges.

We also note that while the TSS sets out indicative pricing levels for ICCs, we have not included comparisons and commentary on these customers. This is because the rates presented for ICCs were ‘average’ rates, indicative only of future trends in prices at a macro level. The development of the proposed 2017-18 tariffs for ICCs is carried out with specific reference to individual customers and connection arrangements. Outcomes are specific to those individual circumstances and changes that may occur to them. Nonetheless, Ergon Energy can confirm that, in the main, there aren’t material differences between each proposed 2017-18 ICC tariff, and the individual indicative tariffs that underpinned the ‘average’ rates in our TSS. Where material differences in rates are apparent, these are attributable to material changes in the customer’s underlying load, demand or connection characteristics since preparing indicative prices for the TSS. This is to be expected given the nature and basis of how ICCs are priced.

5.4.1 Differences in network tariff pricing levels

To satisfy clause 6.18.2(b)(7A) of the NER, Ergon Energy has developed a separate attachment (Attachment 3), which provides a comparison between the indicative 2017-18 rates set out in Appendix A of our TSS, and the proposed 2017-18 rates submitted as part of this Pricing Proposal. The difference is expressed as both an absolute value and as a percentage of the indicative rate submitted.

Overall, the proposed 2017-18 rates are lower than the TSS 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 TSS and the Pricing Proposal. Key inputs impacting rate calculation include:

- the final TAR (refer Section 3.1.1)
- TUOS and Jurisdictional Scheme outcomes (refer to Sections 3.2 and 3.3)
- updating of customer number, energy and demand forecasts which underpin the prices (refer Section 3.4)
- updating of customer profile data used in our tariff models.[47] 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 0, 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 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.

The overall downward reduction in rates from the TSS indicative prices is attributable to total network revenue being less and forecast volumes being higher than estimated at the time the TSS indicative rates were prepared. Overall NUOS revenue is down 4% ($71.15M), DUOS revenue is down 1% ($16M), while our forecast customer numbers and energy consumption has been refined based on latest historical data available. As noted in Sections 3.4 and 5.3.2, we have also made some refinements to our SAC forecasting

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

methodology to take account of more econometric and statistical based principles. The TSS indicative prices were developed using previous forecasting approaches, which were primarily based on extrapolations of historical data. These changes too, have contributed to some differences in forecast volumes between the TSS and our Pricing Proposal.

With respect to materiality we have referenced an increase of over 10% 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 increased by 10% more than the TSS indicative, it is offset by reductions in other charging parameters in that tariff.

Overall of the 209 individual rates in 51 DUOS tariffs, 7 charging parameters have increases greater than 10% compared to the indicatives. 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 2017-18 SAC Small West IBT tariff block 2 and block 3 rates are higher than the TSS indicative rates. Due to the relatively small quantities in revenue and customer numbers, rates in the West Zone are more sensitive to changes in revenue and customer numbers and energy consumed. Block 2 and block 3 is also where the concentration of the impact for variation in residual components occurs, as it is these charging parameters that have been used to recover revenue not recovered through LRMC-based tariff parameters. While our proposed 2017-18 block 2 and 3 rates are higher than the indicatives, they are between 4% and 9% lower than the 2016-17 AER-approved rates.

The proposed 2017-18 Seasonal TOU Energy Business Volume Peak rates in East and Mount Isa Zones are both 22% above the TSS indicative rate. This is primarily attributable to an adjustment to align the proportion of LRMC recovery in these two tariffs with the other SAC Small LRMC tariffs. While this is a larger increase than indicated in our TSS, it corrects the relativity and relationship between the peak rates in the STOUE and the STOUD and allows the market to make decisions between these tariff options on a more transparent basis, consistent with the longer term relativities.

The proposed 2017-18 Mount Isa Zone Seasonal TOU Demand Residential volume peak and off peak volume rates are 17% higher than the TSS indicative rates. This is an increase of 0.1 c/kWh in the volume residual parameters of the tariff compared to the indicatives. The proposed 2017-18 volume rate of 1 c/kWh is unchanged from 2016-17. The volume rate recovers only a small proportion of revenue from this tariff and the proposed rates for the other charging parameters have reductions of 5% and 16% compared to the TSS indicative rates.

Material SAC Large Rate Changes

No material changes compared to the 2017-18 TSS indicative rates.

Material CAC Rate Changes

No material changes compared to the 2017-18 TSS indicative rates.

TUOS and jurisdictional scheme rate changes

As noted above, Attachment 3 also illustrates the same rate comparison for TUOS and jurisdictional scheme charges. The 2017-18 forecasts underpinning the TSS indicative rates and our proposed prices are subject to a number of uncertainties with regard to future volumes and expenditures. For example, Powerlink's final revenue determination for the 2017-22 period is still to be handed down by the AER. Forecast jurisdictional scheme payments to be made by Ergon Energy can also be influenced by various other external factors, including shifts in state government policy and technology.

TUOS rate changes

Overall, the downward reduction in TUOS rates from the TSS indicatives is largely attributable to the reduction in our forecast 2017-18 designated pricing proposal charges to be made to Powerlink. Our forecast TUOS revenue used to set proposed TUOS rates in this Pricing Proposal is based on latest information provided by Powerlink. These latest estimates take into account Powerlink's latest revenue proposal to the AER, which was submitted after our TSS.

It is noted that the variation between the indicative and proposed 2017-18 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 Powerlinks 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

Jurisdictional scheme charges have been adjusted to align with current expectations regarding likely jurisdictional scheme payments to be made in 2017-18. The vast majority of these charges relate to FIT payments expected to be made during 2017-18. Overall our 2017-18 jurisdictional scheme revenue has reduced by 21% ($24.86M), compared to forecasts prepared at the time of the TSS.

5.4.2 Differences in Alternative Control Service pricing levels

Ergon Energy notes that the price cap control mechanism that applies to our Alternative Control Services generally constrains movements in prices to a certain level. Any differences between our indicative 2017-18 tariffs set out in our TSS 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. adjustments to reflect out-turn inflation).

Attachment 3 sets out a comparison of the 2017-18 indicative prices set out in our TSS, and the proposed prices for our Alternative Control Services, as outlined in this Pricing Proposal. Ergon Energy confirms that prices are consistent with those presented in our TSS, and that there are no material differences between our indicative and proposed 2017-18 prices.

5.5 Updated indicative pricing levels

Rule requirement

Clause 6.18.2(e) Where the *Distribution Network Service Provider* submits an annual *pricing proposal*, the revised *indicative pricing schedule* referred to in paragraph (d) mush 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 sets out our latest estimates of indicative prices for the remaining years of the current regulatory control period (2018-19 and 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 3.7 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 and jurisdictional schemes) may also affect future price trends.

Table 5.3: 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,[48] 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: – energy and demand – customer numbers – customer churn. These forecasts are consistent with approach outlined in Section 3.4, 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, taking into account their revised revenue proposal for the 2017–18 to 2021–22 period. ▪ For Avoided TUOS and inter-distributor payments, used the previous year's forecast expense and adjusted it by a forecast inflation rate of 2.50 per cent.[49] ▪ 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.
Jurisdictional scheme	▪ Used high level assumptions regarding the total number of FiT payments we expect to make for the relevant year. These forecasts take into account: – the number of connected inverter energy systems expected to be eligible for

48 Except 2018-19. We have applied an estimated s-factor.
49 For Chumvale, we apply 50 per cent of the applicable CPI increase.

Type of charge	Assumptions applied
	the Solar Bonus Scheme (44 cent) in the relevant year – the mean size of the installed solar arrays – historical monthly export in kWh per unit of installed capacity. In producing these forecasts, we assumed: – There are no major policy or technology shifts affecting customers receiving the 44 cent FiT. – The current trends of factors affecting the 44 cent FiT will continue into the future. ▪ Forecast energy industry levy amounts were based on information provided by the Department of Energy and Water Supply. ▪ Included a forecast jurisdictional scheme over recovery adjustment in 2018-19, noting the final position is not yet known. No adjustments have been applied in future years.

5.6 Publication of information

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 TSS
- 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.[50]

Ergon Energy's AER-approved TSS for the 2017-20 period is currently available on our website. The TSS also contains our current indicative pricing schedule. The indicative pricing schedule is updated each year as part of the annual Pricing Proposal process (refer Attachment 2).

Our 2017-18 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.

As noted in Section 1.7 Ergon Energy publishes a range of additional pricing documents to assist interested parties understand the application of our network tariffs and Alternative Control Services. A number of these documents contain information on our tariff classes and tariffs applicable to each class.

Further information on how we satisfy clause 6.18.9 of the NER is set out in Appendix 2.

[50] NER clauses 6.18.9(a1) and (b)

Appendix 1: Proposed prices

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.

This appendix sets out our proposed prices for our distribution services for 2017-18, including NUOS charges for our Standard Control Service and charges for our various Alternative Control Services. For our Standard Control Services, only tariffs with standardised rates have been published below. Information on our proposed site-specific network tariffs for ICCs and EGs is included in (confidential) Attachment 1.

NUOS prices for Standard Control Services

NUOS charges consist of three components:

- Distribution Use of System (DUOS) charges, which recover our SCS revenue
- Transmission Use of System (TUOS) charges, which recover designated pricing proposal charges of which Powerlink's (the Queensland Transmission Network Service Provider) transmission charges are the main component
- Jurisdictional scheme charges, which recovers amounts we are obligated to pay under jurisdictional scheme programs (e.g. Queensland Solar Bonus Scheme and the energy industry levy)

In this section each building block of NUOS is presented separately. For each tariff NUOS is determined by combining the relevant DUOS, TUOS and jurisdictional scheme charges.

In calculating network charges, the TUOS volume rates need to be adjusted by the customer's applicable Distribution Loss Factor (DLF). The standard 2017-18 DLFs are provided in this appendix. A specific loss factor may be applied where there is a unique network supply configuration.

1.1 DUOS prices

Table A1.1: SAC DUOS prices

Tariff	Charging parameter	Units	Rate
SAC Small default tariffs			
IBT Residential			
IBT Residential East (ERIB)	Fixed	$/day	1.250
	Volume Block 1	$/kWh	0.02150
	Volume Block 2	$/kWh	0.06150
	Volume Block 3	$/kWh	0.09600
IBT Residential West (WRIB)	Fixed	$/day	2.000
	Volume Block 1	$/kWh	0.07100
	Volume Block 2	$/kWh	0.32686
	Volume Block 3	$/kWh	0.37443

Tariff	Charging parameter	Units	Rate
IBT Residential Mount Isa (MRIB)	Fixed	$/day	1.250
	Volume Block 1	$/kWh	0.02150
	Volume Block 2	$/kWh	0.03700
	Volume Block 3	$/kWh	0.05348
IBT Business			
IBT Business East (EBIB)	Fixed	$/day	1.250
	Volume Block 1	$/kWh	0.02500
	Volume Block 2	$/kWh	0.08518
	Volume Block 3	$/kWh	0.12519
IBT Business West (WBIB)	Fixed	$/day	2.000
	Volume Block 1	$/kWh	0.07100
	Volume Block 2	$/kWh	0.33180
	Volume Block 3	$/kWh	0.38624
IBT Business Mount Isa (MBIB)	Fixed	$/day	1.250
	Volume Block 1	$/kWh	0.02500
	Volume Block 2	$/kWh	0.05643
	Volume Block 3	$/kWh	0.07651
SAC Small optional tariffs			
Seasonal TOU Energy Residential			
Seasonal TOU Energy Residential East (ERTOU)	Fixed	$/day	1.250
	Volume Peak	$/kWh	0.38495
	Volume Off Peak	$/kWh	0.04200
Seasonal TOU Energy Residential West (WRTOU)	Fixed	$/day	2.000
	Volume Peak	$/kWh	0.96366
	Volume Off Peak	$/kWh	0.22000
Seasonal TOU Energy Residential Mount Isa (MRTOU)	Fixed	$/day	1.250
	Volume Peak	$/kWh	0.38481
	Volume Off Peak	$/kWh	0.01100
Seasonal TOU Energy Business			
Seasonal TOU Energy Business East (EBTOU)	Fixed	$/day	1.250
	Volume Peak	$/kWh	0.43583
	Volume Off Peak	$/kWh	0.08194
Seasonal TOU Energy Business West (WBTOU)	Fixed	$/day	2.000
	Volume Peak	$/kWh	1.09102
	Volume Off Peak	$/kWh	0.24000
Seasonal TOU Energy Business Mount Isa (MBTOU)	Fixed	$/day	1.250
	Volume Peak	$/kWh	0.43567
	Volume Off Peak	$/kWh	0.04100
Seasonal TOU Demand Residential			
Seasonal TOU Demand Residential East (ERTOUD)	Fixed	$/day	0.000
	Actual Demand Peak	$/kW/mth	76.220
	Actual Demand Off Peak	$/kW/mth	11.500

Tariff	Charging parameter	Units	Rate
	Volume Peak	$/kWh	0.01800
	Volume Off Peak	$/kWh	0.01800
Seasonal TOU Demand Residential West (WRTOUD)	Fixed	$/day	0.000
	Actual Demand Peak	$/kW/mth	190.804
	Actual Demand Off Peak	$/kW/mth	17.000
	Volume Peak	$/kWh	0.13000
	Volume Off Peak	$/kWh	0.13000
Seasonal TOU Demand Residential Mount Isa (MRTOUD)	Fixed	$/day	0.000
	Actual Demand Peak	$/kW/mth	76.193
	Actual Demand Off Peak	$/kW/mth	7.500
	Volume Peak	$/kWh	0.01000
	Volume Off Peak	$/kWh	0.01000
Seasonal TOU Demand Business			
Seasonal TOU Demand Business East (EBTOUD)	Fixed	$/day	0.000
	Actual Demand Peak	$/kW/mth	94.720
	Actual Demand Off Peak	$/kW/mth	10.000
	Volume Peak	$/kWh	0.02500
	Volume Off Peak	$/kWh	0.02500
Seasonal TOU Demand Business West (WBTOUD)	Fixed	$/day	0.000
	Actual Demand Peak	$/kW/mth	237.116
	Actual Demand Off Peak	$/kW/mth	18.000
	Volume Peak	$/kWh	0.15000
	Volume Off Peak	$/kWh	0.15000
Seasonal TOU Demand Business Mount Isa (MBTOUD)	Fixed	$/day	0.000
	Actual Demand Peak	$/kW/mth	94.686
	Actual Demand Off Peak	$/kW/mth	4.000
	Volume Peak	$/kWh	0.01000
	Volume Off Peak	$/kWh	0.01000
SAC Small secondary tariffs			
Controlled load			
Volume Night Controlled East (EVN)	Fixed	$/day	0.094
	Volume	$/kWh	0.04100
Volume Night Controlled West (WVN)	Fixed	$/day	0.118
	Volume	$/kWh	0.08200
Volume Night Controlled Mount Isa (MVN)	Fixed	$/day	0.126
	Volume	$/kWh	0.04100
Volume Controlled East (EVC)	Fixed	$/day	0.094
	Volume	$/kWh	0.04600
Volume Controlled West (WVC)	Fixed	$/day	0.118
	Volume	$/kWh	0.10700
Volume Controlled Mount Isa (MVC)	Fixed	$/day	0.126
	Volume	$/kWh	0.04600

Tariff	Charging parameter	Units	Rate
Unmetered supply			
Unmetered supply			
Unmetered Supply East (EVU, EVUMI, EVUMA)	Fixed	$/day	0.006
	Volume	$/kWh	0.15878
Unmetered Supply West (WVU, WVUMI, WVUMA)	Fixed	$/day	0.269
	Volume	$/kWh	0.18297
Unmetered Supply Mount Isa (MVU, MVUMI, MVUMA)	Fixed	$/day	0.205
	Volume	$/kWh	0.01592

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 blocks	Block 1: <2.74 kWh; <1,000 kWh per annum Block 2: 2.74 - 16.43 kWh; 1,000 - 6,000 kWh per annum Block 3: >16.43 kWh; >6,000 kWh per annum
Business – consumption blocks	Block 1: <2.74 kWh; <1,000 kWh per annum Block 2: 2.74 - 54.76 kWh; 1,000 - 20,000 kWh per annum Block 3: >54.76 kWh; >20,000 kWh per annum
SAC Small optional tariffs	
Seasonal TOU Energy tariffs – Residential and Business	
Opt-in arrangements	A customer (or their retailer) must request a tariff change to opt in to these tariffs. Tariff access considerations include suitable metering.
Residential – time periods	Peak: 3:00pm to 9:30pm on all summer days Off-Peak: All other times

Residential - consumption blocks:

Block	Daily kWh	Annual equivalent kWh
Block 1	<2.74 kWh	<1,000 kWh per annum
Block 2	2.74 - 16.43 kWh	1,000 - 6,000 kWh per annum
Block 3	>16.43 kWh	>6,000 kWh per annum

Business – consumption blocks:

Block	Daily kWh	Annual equivalent kWh
Block 1	<2.74 kWh	<1,000 kWh per annum
Block 2	2.74 - 54.76 kWh	1,000 - 20,000 kWh per annum
Block 3	>54.76 kWh	>20,000 kWh per annum

Residential – time periods:

Peak	3:00pm to 9:30pm on all summer days
Off-Peak	All other times

Application of tariff and charges	
	Note: 'Summer' is defined as the months of December, January and February
Business – time periods	Peak: 10:00am to 8:00pm on summer weekdays Off-Peak: All other times Note: 'Summer' is defined as the months of December, January and February
Seasonal TOU Demand tariffs – Residential and Business	
Opt-in arrangements	A customer (or their retailer) must request a tariff change to opt in to these tariffs. Tariff access considerations include suitable metering.
Residential – time periods	Peak demand: 3:00pm to 9:30pm all summer days Off-Peak demand: 3:00pm to 9:30pm all non-summer days Energy: An any time energy (volume) charge applies to all metered consumption Note: 'Summer' is defined as the months of December, January and February
Business – time periods	Peak demand: 10:00am to 8:00pm on summer weekdays Off-Peak demand: 10:00am to 8:00pm on non-summer weekdays Energy: An any time energy (volume) charge applies to all metered consumption Note: 'Summer' is defined as the months of December, January and February
Chargeable demand quantities	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)
Demand charges	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 –

Application of tariff and charges	
	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.
Volume charges	The volume calculation is based on a $/kWh rate applied to all metered kWh consumption for the billing period (both peak and off-peak).

Table A1.2: SAC Large DUOS prices

Tariff	Charging parameter	Units	Rate
SAC Large default tariffs			
Demand Large			
Demand Large East (EDLT)	Fixed	$/day	360.000
	Actual Demand	$/kW/mth	20.000
	Volume	$/kWh	0.00400
Demand Large West (WDLT)	Fixed	$/day	1,131.773
	Actual Demand	$/kW/mth	75.000
	Volume	$/kWh	0.00900
Demand Large Mount Isa (MDLT)	Fixed	$/day	234.000
	Actual Demand	$/kW/mth	13.000
	Volume	$/kWh	0.00500
Demand Medium			
Demand Medium East (EDMT)	Fixed	$/day	136.000
	Actual Demand	$/kW/mth	24.638
	Volume	$/kWh	0.00400
Demand Medium West (WDMT)	Fixed	$/day	361.000
	Actual Demand	$/kW/mth	88.737
	Volume	$/kWh	0.00600
Demand Medium Mount Isa (MDMT)	Fixed	$/day	81.294
	Actual Demand	$/kW/mth	16.600
	Volume	$/kWh	0.00500
Demand Small			
Demand Small East (EDST)	Fixed	$/day	38.423
	Actual Demand	$/kW/mth	33.000
	Volume	$/kWh	0.00400
Demand Small West (WDST)	Fixed	$/day	94.000
	Actual Demand	$/kW/mth	90.298
	Volume	$/kWh	0.00500
Demand Small Mount Isa (MDST)	Fixed	$/day	23.843
	Actual Demand	$/kW/mth	20.000
	Volume	$/kWh	0.00500
SAC-Large optional tariffs			
Seasonal TOU Demand			

Tariff	Charging parameter	Units	Rate
Seasonal TOU Demand East (ESTOUDC)	Fixed	$/day	30.000
	Actual Demand Peak	$/kW/mth	56.240
	Actual Demand Off Peak	$/kW/mth	9.500
	Volume Peak	$/kWh	0.00000
	Volume Off Peak	$/kWh	0.02500
Seasonal TOU Demand West (WSTOUDC)	Fixed	$/day	100.000
	Actual Demand Peak	$/kW/mth	140.787
	Actual Demand Off Peak	$/kW/mth	38.000
	Volume Peak	$/kWh	0.00000
	Volume Off Peak	$/kWh	0.04500
Seasonal TOU Demand Mount Isa (MSTOUDC)	Fixed	$/day	20.000
	Actual Demand Peak	$/kW/mth	56.220
	Actual Demand Off Peak	$/kW/mth	2.000
	Volume Peak	$/kWh	0.00000
	Volume Off Peak	$/kWh	0.01000

Notes:

Application of tariff and charges	
SAC Large default tariffs	
Demand Large, Demand Medium, Demand Small	
Actual demand charge	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.
Threshold above which demand charge applies	Demand Large: 400kW Demand Medium: 120kW Demand Small: 30kW Note: applies for DUOS and TUOS charges
SAC Large optional tariffs	
Seasonal TOU Demand	
Opt-in (and opt-out) arrangements	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.
Time periods	. Peak demand: 10:00am to 8:00pm on summer weekdays Off-Peak demand: All times during non-summer months

Application of tariff and charges	
	Peak energy: All times during summer months Off-peak energy: All times during non-summer months Note: 'Summer' is defined as the months of December, January and February
Demand calculation (peak)	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 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 2017-18, 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	Rate
CAC default tariffs			
CAC 66 kV			
CAC 66 kV East (EC66)	Fixed	$/day	120.000
	Connection Unit	$/day/connection unit	9.451
	Capacity	$/kVA/mth of AD	3.520
	Actual Demand	$/kVA/mth	2.500
	Volume	$/kWh	0.00500
	Excess Reactive Power	$/excess kVAr	4.000
CAC 66 kV West (WC66)	Fixed	$/day	117.000
	Connection Unit	$/day/connection	9.451

Tariff	Charging parameter	Units	Rate
		unit	
	Capacity	$/kVA of AD/mth	12.000
	Actual Demand	$/kVA/mth	49.000
	Volume	$/kWh	0.01420
	Excess Reactive Power	$/excess kVAr	4.000
CAC 66 kV Mount Isa (MC66)	Fixed	$/day	POA
	Connection Unit	$/day/connection unit	POA
	Capacity	$/kVA of AD/mth	POA
	Actual Demand	$/kVA/mth	POA
	Volume	$/kWh	POA
	Excess Reactive Power	$/excess kVAr	POA
CAC 33 kV			
CAC 33 kV East (EC33)	Fixed	$/day	55.000
	Connection Unit	$/day/connection unit	9.451
	Capacity	$/kVA of AD/mth	4.444
	Actual Demand	$/kVA/mth	2.500
	Volume	$/kWh	0.00500
	Excess Reactive Power	$/excess kVAr	4.000
CAC 33 kV West (WC33)	Fixed	$/day	50.000
	Connection Unit	$/day/connection unit	9.451
	Capacity	$/kVA of AD/mth	18.300
	Actual Demand	$/kVA/mth	25.000
	Volume	$/kWh	0.01420
	Excess Reactive Power	$/excess kVAr	4.000
CAC 33 kV Mount Isa (MC33)	Fixed	$/day	POA
	Connection Unit	$/day/connection unit	POA
	Capacity	$/kVA of AD/mth	POA
	Actual Demand	$/kVA/mth	POA
	Volume	$/kWh	POA
	Excess Reactive Power	$/excess kVAr	POA
CAC 22/11 kV Bus			
CAC 22/11 kV Bus East (EC22B)	Fixed	$/day	41.000
	Connection Unit	$/day/connection unit	9.451
	Capacity	$/kVA of AD/mth	5.100
	Actual Demand	$/kVA/mth	3.100
	Volume	$/kWh	0.00500
	Excess Reactive Power	$/excess kVAr	4.000
CAC 22/11 kV Bus West (WC22B)	Fixed	$/day	POA
	Connection Unit	$/day/connection unit	POA
	Capacity	$/kVA of AD/mth	POA
	Actual Demand	$/kVA/mth	POA
	Volume	$/kWh	POA

Tariff	Charging parameter	Units	Rate
	Excess Reactive Power	$/excess kVAr	POA
CAC 22/11 kV Bus Mount Isa (MC22B)	Fixed	$/day	POA
	Connection Unit	$/day/connection unit	POA
	Capacity	$/kVA of AD/mth	POA
	Actual Demand	$/kVA/mth	POA
	Volume	$/kWh	POA
	Excess Reactive Power	$/excess kVAr	POA
CAC 22/11 kV Line			
CAC 22/11 kV Line East (EC22L)	Fixed	$/day	33.000
	Connection Unit	$/day/connection unit	9.451
	Capacity	$/kVA of AD/mth	10.600
	Actual Demand	$/kVA/mth	6.200
	Volume	$/kWh	0.00500
	Excess Reactive Power	$/excess kVAr	4.000
CAC 22/11 kV Line West (WC22L)	Fixed	$/day	32.000
	Connection Unit	$/day/connection unit	9.451
	Capacity	$/kVA of AD/mth	28.801
	Actual Demand	$/kVA/mth	26.700
	Volume	$/kWh	0.01420
	Excess Reactive Power	$/excess kVAr	4.000
CAC 22/11 kV Line Mount Isa (MC22L)	Fixed	$/day	POA
	Connection Unit	$/day/connection unit	POA
	Capacity	$/kVA of AD/mth	POA
	Actual Demand	$/kVA/mth	POA
	Volume	$/kWh	POA
	Excess Reactive Power	$/excess kVAr	POA
CAC optional tariffs			
Seasonal TOU Demand Higher Voltage			
Seasonal TOU Demand CAC Higher Voltage East (66/33 kV) (EC66TOU)	Fixed	$/day	0.000
	Connection Unit	$/day/connection unit	9.451
	Actual Demand Peak	$/kVA/month	11.000
	Capacity Off Peak	$/kVA/mth of AD	6.000
	Volume Peak	$/kWh	0.00000
	Volume Off Peak	$/kWh	0.00400
	Excess Reactive Power	$/excess kVAr	4.000
Seasonal TOU Demand CAC Higher Voltage West (66/33 kV) (WC66TOU)	Fixed	$/day	0.000
	Connection Unit	$/day/connection unit	9.451
	Actual Demand Peak	$/kVA/month	27.667
	Capacity Off Peak	$/kVA/mth of AD	20.000
	Volume Peak	$/kWh	0.00000
	Volume Off Peak	$/kWh	0.03000
	Excess Reactive Power	$/excess kVAr	4.000

Tariff	Charging parameter	Units	Rate
Seasonal TOU Demand CAC Higher Voltage Mount Isa (66/33 kV) (MC66TOU)	Fixed	$/day	POA
	Connection Unit	$/day/connection unit	POA
	Actual Demand Peak	$/kVA/month	POA
	Capacity Off Peak	$/kVA/mth of AD	POA
	Volume Peak	$/kWh	POA
	Volume Off Peak	$/kWh	POA
	Excess Reactive Power	$/excess kVAr	POA
Seasonal TOU Demand CAC 22/11 kV Bus			
Seasonal TOU Demand CAC 22/11 kV Bus East (EC22BTOU)	Fixed	$/day	0.000
	Connection Unit	$/day/connection unit	9.451
	Actual Demand Peak	$/kVA/month	39.600
	Capacity Off Peak	$/kVA/mth of AD	4.000
	Volume Peak	$/kWh	0.00000
	Volume Off Peak	$/kWh	0.00400
	Excess Reactive Power	$/excess kVAr	4.000
Seasonal TOU Demand CAC 22/11 kV Bus West (WC22BTOU)	Fixed	$/day	POA
	Connection Unit	$/day/connection unit	POA
	Actual Demand Peak	$/kVA/month	POA
	Capacity Off Peak	$/kVA/mth of AD	POA
	Volume Peak	$/kWh	POA
	Volume Off Peak	$/kWh	POA
	Excess Reactive Power	$/excess kVAr	POA
Seasonal TOU Demand CAC 22/11 kV Bus Mount Isa (MC22BTOU)	Fixed	$/day	POA
	Connection Unit	$/day/connection unit	POA
	Actual Demand Peak	$/kVA/month	POA
	Capacity Off Peak	$/kVA/mth of AD	POA
	Volume Peak	$/kWh	POA
	Volume Off Peak	$/kWh	POA
	Excess Reactive Power	$/excess kVAr	POA
Seasonal TOU Demand CAC 22/11 kV Line			
Seasonal TOU Demand CAC 22/11 kV Line East (EC22LTOU)	Fixed	$/day	0.000
	Connection Unit	$/day/connection unit	9.451
	Actual Demand Peak	$/kVA/month	72.333
	Capacity Off Peak	$/kVA/mth of AD	8.000
	Volume Peak	$/kWh	0.00000
	Volume Off Peak	$/kWh	0.00400
	Excess Reactive Power	$/excess kVAr	4.000
Seasonal TOU Demand CAC 22/11 kV Line West (WC22LTOU)	Fixed	$/day	0.000
	Connection Unit	$/day/connection unit	9.451
	Actual Demand Peak	$/kVA/month	181.000
	Capacity Off Peak	$/kVA/mth of AD	33.000

Tariff	Charging parameter	Units	Rate
	Volume Peak	$/kWh	0.00000
	Volume Off Peak	$/kWh	0.03000
	Excess Reactive Power	$/excess kVAr	4.000
Seasonal TOU Demand CAC 22/11 kV Line Mount Isa (MC22LTOU)	Fixed	$/day	POA
	Connection Unit	$/day/connection unit	POA
	Actual Demand Peak	$/kVA/month	POA
	Capacity Off Peak	$/kVA/mth of AD	POA
	Volume Peak	$/kWh	POA
	Volume Off Peak	$/kWh	POA
	Excess Reactive Power	$/excess kVAr	POA

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
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.
Time periods	Peak demand: 10:00am to 8:00pm on summer weekdays Capacity charge (off-peak): 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

Application of tariff and charges	
	Volume charge (off-peak): Applies to all metered consumption during non-summer months. Note: 'Summer' is defined as the months of December, January and February.
Actual demand peak charge	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.
Capacity off-peak charge	The capacity 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.
Volume off-peak charge	The off-peak volume calculation uses total metered kWh consumption at all times during non-summer months.

1.2 TUOS prices

Table A1.4: SAC Small TUOS prices – Primary tariffs[a]

Transmission pricing region	TUOS tariff	TUOS charge	Units	Rate
Transmission Region 1	T1	Fixed	$/day	0.104
		Volume	$/kWh	0.00859
Transmission Region 2	T2	Fixed	$/day	0.196
		Volume	$/kWh	0.01042
Transmission Region 3	T3	Fixed	$/day	0.310
		Volume	$/kWh	0.01333
Transmission Region 4[b]	T4	Fixed	$/day	0.137
		Volume	$/kWh	0.00074

Notes:

a) IBT, STOUE and STOUD.
b) Mount Isa network.

Table A1.5: SAC Small TUOS prices – Secondary and unmetered tariffs[a]

Transmission pricing region	TUOS tariff	TUOS charge	Units	Rate
Transmission Region 1	T1	Volume	$/kWh	0.00859
Transmission Region 2	T2	Volume	$/kWh	0.01042
Transmission Region 3	T3	Volume	$/kWh	0.01333
Transmission Region 4	T4	Volume	$/kWh	0.00074

Notes:

a) Volume Controlled, Volume Night Controlled and Unmetered Supply.

Table A1.6: SAC Large TUOS prices

Transmission pricing region	TUOS tariff	TUOS charge	Units	Rate
Demand Large				
Transmission Region 1	T1	Fixed	$/day	14.985
		Actual Demand	$/kW of AMD/month	0.915
		Volume	$/kWh	0.00859
Transmission Region 2	T2	Fixed	$/day	32.489
		Actual Demand	$/kW of AMD/month	2.202
		Volume	$/kWh	0.01042
Transmission Region 3	T3	Fixed	$/day	61.410
		Actual Demand	$/kW of AMD/month	4.396
		Volume	$/kWh	0.01333
Transmission Region 4	T4	Fixed	$/day	12.637
		Actual Demand	$/kW of AMD/month	0.806
		Volume	$/kWh	0.00074
Demand Medium				
Transmission Region 1	T1	Fixed	$/day	6.566
		Actual Demand	$/kW of AMD/month	0.915
		Volume	$/kWh	0.00859
Transmission Region 2	T2	Fixed	$/day	12.227
		Actual Demand	$/kW of AMD/month	2.202
		Volume	$/kWh	0.01042
Transmission Region 3	T3	Fixed	$/day	20.969
		Actual Demand	$/kW of AMD/month	4.396
		Volume	$/kWh	0.01333
Transmission Region 4	T4	Fixed	$/day	5.217
		Actual Demand	$/kW of AMD/month	0.806
		Volume	$/kWh	0.00074
Demand Small				
Transmission Region 1	T1	Fixed	$/day	3.859
		Actual Demand	$/kW of AMD/month	0.915
		Volume	$/kWh	0.00859
Transmission Region 2	T2	Fixed	$/day	5.715
		Actual Demand	$/kW of AMD/month	2.202
		Volume	$/kWh	0.01042
Transmission Region 3	T3	Fixed	$/day	7.971
		Actual Demand	$/kW of AMD/month	4.396
		Volume	$/kWh	0.01333
Transmission Region 4	T4	Fixed	$/day	2.832
		Actual Demand	$/kW of AMD/month	0.806
		Volume	$/kWh	0.00074
Seasonal Time-of-Use Demand				
Transmission Region 1	T1	Fixed	$/day	4.010

Transmission pricing region	TUOS tariff	TUOS charge	Units	Rate
		Actual Demand Peak	$/kW of AMD/month	0.915
		Actual Demand Off Peak	$/kW of AMD/month	0.915
		Volume	$/kWh	0.00859
Transmission Region 2	T2	Fixed	$/day	6.076
		Actual Demand Peak	$/kW of AMD/month	2.202
		Actual Demand Off Peak	$/kW of AMD/month	2.202
		Volume	$/kWh	0.01042
Transmission Region 3	T3	Fixed	$/day	8.693
		Actual Demand Peak	$/kW of AMD/month	4.396
		Actual Demand Off Peak	$/kW of AMD/month	4.396
		Volume	$/kWh	0.01333
Transmission Region 4	T4	Fixed	$/day	2.965
		Actual Demand Peak	$/kW of AMD/month	0.806
		Actual Demand Off Peak	$/kW of AMD/month	0.806
		Volume	$/kWh	0.00074

Table A1.7: CAC TUOS prices – All tariffs

Transmission pricing region	TUOS tariff	TUOS charge	Units	Rate
Transmission Region 1	T1	Fixed	$/day	100.912
		Capacity	$/kVA of AD/month	0.715
		Volume	$/kWh	0.00994
Transmission Region 2	T2	Fixed	$/day	72.241
		Capacity	$/kVA of AD/month	1.546
		Volume	$/kWh	0.01169
Transmission Region 3	T3	Fixed	$/day	72.786
		Capacity	$/kVA of AD/month	3.258
		Volume	$/kWh	0.01523

Notes:

Application of charges SAC small, SAC Large and CAC

For the TUOS volume charge, the metered consumption for all blocks is multiplied by the DLF and then applied to the TUOS volume rate.

Application of charges CAC

The TUOS capacity charge is applied to the greater of the authorised kVA demand or any time maximum kVA demand at any time in each month of the year.

Table A1.8: Standard DLFs applicable in 2017-18 [a]

Network Level	East	West	Mount Isa
Sub-transmission Bus	1.006	1.029	1.001
Sub-transmission Line	1.011	1.057	1.005
22/11 kV Bus	1.015	1.065	1.007
22/11 kV Line	1.030	1.097	1.035
LV Bus	1.073	1.149	1.061
LV Line	1.096	1.192	1.070

Notes:

a) DLFs are applied to the metered consumption for the calculation of TUOS volume charges. The DLF applicable may be a standard loss factor or specific loss factor (in instances where there is a unique network supply configuration). DLFs are re-calculated each year.

1.3 Jurisdictional scheme charges

Table A1.9: Jurisdictional scheme charges [a]

Customer group	Charge	Units	Rate
SAC Small Primary Tariffs	Fixed	$/day	0.142
	Volume	$/kWh	0.00838
SAC Small Controlled Load Tariffs	Fixed	$/day	N/A
	Volume	$/kWh	0.00838
SAC Large	Fixed	$/day	0.766
	Volume	$/kWh	0.00110
CAC	Fixed	$/day	13.991
	Volume	$/kWh	0.00069
ICC	Fixed	$/day	111.712
	Volume	$/kWh	0.142

Notes:

a) Applicable to all tariffs, except unmetered supply and Embedded Generators.

Alternative Control Services prices

1.1 Fee based services

Table A1.10: Fee based services prices

Service	2017-18 GST Exclusive	
	Total price [a]	Call out fee [b]
Application fee - Basic or standard connection	$888.45	n/a
Application fee - Basic or standard connection - Micro-embedded generators	$48.60	n/a
Application fee - Basic or standard connection - Micro-embedded generators - Technical assessment required	$220.71	n/a
Application fee - Real estate development connection	$930.22	n/a

Service	2017-18 GST Exclusive Total price [a]	Call out fee [b]
Protection and Power Quality assessment prior to connection	$1,376.77	n/a
Temporary connection, not in permanent position - single phase metered - urban/short rural feeders	$584.98	$117.00
Temporary connection, not in permanent position - single phase metered - long rural/isolated feeders	$935.96	$467.98
Temporary connection, not in permanent position - multi phase metered - urban/short rural feeders	$584.98	$117.00
Temporary connection, not in permanent position - multi phase metered - long rural/isolated feeders	$935.96	$467.98
Supply abolishment during business hours - urban/short rural feeders	$350.99	$117.00
Supply abolishment during business hours - long rural/isolated feeders	$701.97	$467.98
De-energisation during business hours - urban/short rural feeders	$98.03	$38.97
De-energisation during business hours - long rural/isolated feeders	$584.98	$467.98
Re-energisation during business hours - urban/short rural feeders	$77.95	$38.97
Re-energisation during business hours - long rural/isolated feeders	$545.20	$467.98
Re-energisation during business hours - after de-energisation for debt - urban/short rural feeders	$77.95	$38.97
Re-energisation during business hours - after de-energisation for debt - long rural/isolated feeders	$545.20	$467.98
Accreditation of alternative service providers - real estate developments	$903.50	n/a
Install new or replacement meter (Type 5 and 6) - Single phase - urban/short rural feeder	$344.42	$63.44
Install new or replacement meter (Type 5 and 6) - Single phase - long rural/isolated feeder	$533.97	$253.74
Install new or replacement meter (Type 5 and 6) - Dual element - urban/short rural feeder	$421.85	$63.44
Install new or replacement meter (Type 5 and 6) - Dual element - long rural/isolated feeder	$611.41	$253.74
Install new or replacement meter (Type 5 and 6) - Polyphase - urban/short rural feeder	$530.25	$63.44
Install new or replacement meter (Type 5 and 6) - Polyphase - long rural/isolated feeder	$719.80	$253.74
Install new or replacement meter (CT) - urban/short rural feeder	$2,519.12	$121.38
Install new or replacement meter (CT) - long rural/isolated feeder	$2,881.80	$485.51

1.2 Quoted services

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

Further, where Ergon Energy attends a premise to perform a service and is unable to complete the job for reasons outside of our control, such as a locked gate, we will charge a call out fee.

Table A1.11: Potential indicative quoted services prices

Service	2017-18 GST Exclusive
Application fee - Negotiated connection	$ 1,144.62
Application fee - Negotiated connection - Micro-embedded generators	$509.00
Application fee - Negotiated - Major customer connection	$7,367.18
Carrying out planning studies and analysis relating to connection applications	$2,327.28
Feasibility and concept scoping, including planning and design, for major customer connections	$18,715.83
Tender process	$10,895.57
Pre-connection site inspection	$1,350.50
Provision of site-specific connection information and advice	$796.84
Preparation of preliminary designs and planning reports for major customer connections, including project scopes and estimates	$9,806.01
Customer build, own and operate consultation services	$77,667.23
Detailed enquiry response fee - embedded generation	$25,962.35
Design and construction of connection assets for major customers	$9,253,417.00
Commissioning and energisation of major customer connections	$44,783.83
Design and construction for real estate developments	$176,544.50
Commissioning and energisation of real estate development connections	$7,015.21
Removal of network constraint for embedded generator	$567,951.01
Move point of attachment - single/multi phase	$3,793.99
Re-arrange connection assets at customer's request	$68,551.92
Protection and Power Quality assessment after connection	$2,900.86
Temporary de-energisation - no dismantling	$757.26
LV Service line drop and replace - physical dismantling	$1,098.14
HV Service line drop and replace	$4,631.24
Supply enhancement	$1,323.89
Provision of connection services above minimum requirements	$311,723.22
Upgrade from overhead to underground service	$8,923.62
Rectification of illegal connections or damage to overhead or underground service cables	$223.45
De-energisation after business hours	$146.90
Re-energisation after business hours	$116.81
Accreditation of alternative service providers - major customer connections	$6,484.02
Approval of third party design - major customer connections	$14,527.42
Approval of third party design - real estate developments	$203.00
Construction audit - major customer connections	$94,240.39
Construction audit - real estate developments	$1,198.57
Approval of third party materials	$19,532.54
Special meter read	$130.48
Meter test	$461.79

Service	2017-18 GST Exclusive
Meter inspection and investigation on request	$297.93
Metering alteration	$2,946.07
Exchange meter	$297.93
Type 5 to 7 non-standard metering services	$422.85
Removal of a meter (Type 5 & 6)	$140.43
Meter re-seal	$603.31
Install new or replacement meter - after hours	$430.23
Change time switch	$223.45
Change tariff	$230.90
Reprogram card meters	$1,340.69
Install metering related load control	$297.93
Removal of load control device	$297.93
Change load control relay channel	$148.97
Services provided in relation to a Retailer of Last Resort (ROLR) event	$2,908.19
Non-standard network data requests	$726.37
Provision of services for approved unmetered supplies	$105.34
Customer or retailer requested appointments	$772.59
Removal/rearrangement of network assets	$317,646.31
Aerial markers	$750.98
Tiger tails	$2,536.09
Assessment for non-exporting generator applications	$1,815.93
Witness testing	$4,003.24
Removal/rearrangement of public lighting assets	$21,632.21

1.3 Default Metering Services

Table A1.12: Annual metering services charges

Metering service type	Cost recovery type	2017-18 Fixed charge ($ p.a.) GST Exclusive
Primary	Non–capital	$40.94
	Capital	$11.42
Controlled load	Non–capital	$15.05
	Capital	$4.20
Embedded generation	Non–capital	$10.18
	Capital	$2.84

Table A1.13: Call out fees for final meter reads

Call out fee - Final meter reads	2017-18 Fixed charge ($/call out) GST Exclusive
Call out fee - Final meter read - Urban/short rural feeder	$54.66
Call out fee - Final meter read - Long rural/isolated feeder	$218.65

1.4 Public Lighting Services

Table A1.14: Daily public lighting charges

Public Lighting Services	2017-18 Fixed charge ($/day/light) GST Exclusive
EO&O - Major	$1.1558
EO&O - Minor	$0.6886
G&EO - Major	$0.4667
G&EO - Minor	$0.3057

Table A1.15: Public lighting exit fees

Public lighting exit fee	2017-18 Fixed charge ($/light) GST Exclusive
EO&O - Major - Exit fee	$1,459
EO&O - Minor - Exit fee	$882
G&EO - Major - Exit fee	$241
G&EO - Minor - Exit fee	$205

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
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 3.1.2 provides further explanation on DUOS charging arrangements for generators. As highlighted in Section 1.7 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.
6.18.2(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)	Set out the proposed tariffs for each tariff class that is specified in the tariff structure statement for the relevant regulatory control period.	Tariff schedules for Standard Control Services, including site-specific network tariffs for ICCs and EGs are included in (confidential) Attachment 1. Appendix 1 also details proposed 2017-18 prices for network tariffs with standardised rates. Tariff schedules for Alternative Control Services are provided in Appendix 1. The 2017-18 tariffs and tariff structures for Standard Control Services and Alternative Control Services are consistent with our TSS.
6.18.2(b)(3)	Set out the charging parameters and the elements of service to which each charging parameter relates.	For Standard Control Services, details of the charging parameters and the elements of the service to which each relates are set out in Section 2.2. For Alternative Control Services, the charging parameters 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)	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.	Weighted average revenue calculations for each Standard Control Service tariff class are set out in Section 3.1.4.

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
6.18.2(b)(5)	Set out the nature of any variation or adjustment to the tariff that could occur during the course of the regulatory year and the basis on which it could occur.	Variations and adjustments which could apply to tariffs during 2017-18 are set out in Section 5.2.
6.18.2(b)(6)	Set out how designated pricing proposal charges incurred by distributors for TUOS services are to be passed through to customers and any adjustments to tariffs resulting from over or under recovery of those charges in the previous regulatory year.	The method of passing through designated pricing proposal charges (TUOS) to customers is addressed in Section 3.2.
6.18.2(b)(6A)	Set out how jurisdictional scheme amounts for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from the over or under recovery of those amounts.	The method of passing through jurisdictional scheme amounts to customers is addressed in Section 3.3
6.18.2(b)(6B)	Describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria.	There have been no changes to the jurisdictional schemes since their last jurisdictional scheme approval dates. Section 3.3.2 provides further details.
6.18.2(b)(7)	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 and the Distribution Determination. Ergon Energy has demonstrated compliance with TSS throughout this Pricing Proposal.
6.18.2(b)(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.	Attachment 2 sets out our revised indicative pricing levels for 2018-20, updated to take into account this Pricing Proposal. Differences between 2017-18 indicative pricing levels (as set out in our TSS) and the proposed 2017-18 tariffs is explained in Section 5.4
6.18.2(b)(8)	Describe the nature and extent of change from the previous regulatory year and demonstrate that the changes comply with the NER and any applicable Distribution Determination.	Ergon Energy is proposing some changes to our Standard Control Services and Alternative Control Services in 2017-18. Variations and adjustments incorporated into this year's Pricing Proposal are set out in Sections 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) and (e)	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.
6.18.3(b)	Demonstrate that each customer for Direct Control Services is a member of at least one tariff class.	Assignment of each customer to a tariff class is demonstrated in Sections 2.1 and 4.1.
6.18.3 (c)	Set out separate tariff classes for Standard Control Services and Alternative Control Services.	Tariff classes for Standard and Alternative Control Services are set out in Sections 2.1 and 4.1 respectively.

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
6.18.3(d)(1) and (2)	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. Default Metering Services and Public Lighting Services are provided to customers who require those services and grouping is undertaken on this basis.
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.	Our TSS addresses how we apply the pricing principles contained in the NER. Our considerations around adjustments to tariffs to satisfy consumer impact principles and other regulatory obligations are set out in Section 5.1.3.
6.18.5(e)(1) and (2)	Demonstrate that revenue from a tariff class lies on or between the stand alone and avoidable cost.	Stand alone and avoidable cost assessments are provided in Sections 3.1.6 and 4.5.1. The calculation of these estimates for Standard Control Services is provided in Attachment 1.
6.18.5(f)	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.	LRMC is dealt with in Sections 3.1.7 and 4.5.2. 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)	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)	A description of our approach to structuring network tariffs to recover efficient costs and allowed revenue for our Standard Control Services is set out in Sections 3.1.8. Section 4.5.3 sets out our considerations for Alternative Control Services.
6.18.5(h)	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.	Customer impact considerations of changes in tariffs from the previous regulatory year are dealt with in Sections 5.1.1.
6.18.5(i)	Demonstrate that the structure of each tariff is reasonably capable of being understood by customers.	Ergon Energy has applied the tariff structures as set out in our TSS in establishing tariffs for 2017-18. Section 5.1.2 and Sections 6.6 and 12.6 of our TSS provide further information on how we meet this pricing principle.
6.18.5(j)	Demonstrate that each tariff complies with the NER and all applicable regulatory instruments.	Ergon Energy confirms that our 2017-18 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)	Demonstrate that the weighted average revenue for a Standard Control Service tariff class does not exceed that for the previous year by more than the "permissible percentage" defined in 6.18.6(c) of the NER.	Side constraints are dealt with in Section 3.1.5.
6.18.6(c)(1) and (2)	Demonstrate the "permissible percentage" has been calculated in accordance with the definition set out in this clause of the NER.	Side constraints are dealt with in Section 3.1.5.
6.18.6(d)(1), (2),(3) and (4)	Demonstrate that designated pricing proposal charges (TUOS), pass throughs and jurisdictional scheme amounts were removed from the calculation of the side constraint.	Side constraints are dealt with in Section 3.1.5

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
6.18.7(a)	Demonstrate that the tariffs passed on, to customers, are the designated pricing proposal charges (TUOS) to be incurred by Ergon Energy for TUOS services.	Designated pricing proposal charges (TUOS) passed on to customers are dealt with in Section 3.2.
6.18.7(b)	Demonstrate that the designated pricing proposal charges (TUOS) passed on to customers do not exceed the forecast charges adjusted for over or under recovery.	Designated pricing proposal charges (TUOS) passed on to customers are dealt with in Section 3.2.
6.18.7(c)(1), (2) and (3)	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.	Designated pricing proposal charges (TUOS) passed on to customers are dealt with in Section 3.2.
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	Ergon Energy confirms our designated pricing proposal charges (TUOS) do not include any amounts relating to our revenue cap, jurisdictional schemes or any other amounts recovered from another DNSP. TUOS charges passed on to customers are dealt with in Section 3.2.
6.18.7A (a), (b) and (c)	Demonstrate that tariffs passed on to customersare the jurisdictional scheme amounts to be incurred by Ergon Energy for approved jurisdictional schemes in accordance with 6.18.7A of the NER.	Our approach to applying jurisdictional scheme amounts to customer tariffs is provided in Section 3.3.
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 Sections 3.4.
6.18.9(a)(1)	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)	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)	Demonstrate that Ergon Energy maintains 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. A separate statement will also be published on Ergon Energy's website to satisfy this requirement.
6.18.9(a1)	Demonstrate that the tariff structure statement and accompanying indicative pricing schedule is published on Ergon Energy's website within 5 business days after the AER publishes the distribution determination.	The expected price trends are set out in and will be published separately on our website.

Clause	Obligation	Demonstration of compliance in this Pricing Proposal
6.18.9(b)	Demonstrate that the posting of information required under clause 6.18.9(a) for a particular regulatory year is posted on Ergon Energy's website 5 business days after the AER publishes an approved pricing proposal.	This Pricing Proposal and non-confidential supporting attachments will be published on Ergon Energy's website by the appropriate date. Ergon Energy will also separately publish a statement of tariff classes and tariffs on our website. Ergon Energy's supporting network pricing documentation, as set out in Section 1.7, will also be published on our website.
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. In accordance with the AER's Confidentiality Guideline, Ergon Energy has provided both public and confidential versions of our Pricing Proposal. Our confidentiality claims relating to content within our Pricing Proposal and its attachments and appendices are set out in Appendix 4. All confidential information, including information relating to individual customers has been redacted from public versions.

Table A2.2: Compliance with the Distribution Determination

Obligation	Demonstration of compliance in this Pricing Proposal
Demonstrate that our revenue is consistent with the TAR formula set out in Figure 14.1 of Attachment 14 of the Distribution Determination.	This is demonstrated in Section 3.1.1 and Attachment 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.	In 2017-18, Ergon Energy has applied the X factor based on cost of debt updates provided by the AER on 9 March 2017.
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 2017-18 Ergon Energy applied the DMIS carryover amount as part of the TAR calculations in 2016-17.
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.	Side constraints are dealt with in Section 3.1.5. We have applied the formula set out in the Distribution Determination.
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.	Our DUOS unders and overs account is set out in Section 3.1.1. This section also details the unders/overs adjustment needed to move the balance of the DUOS unders and overs account to, as close as practical, zero.
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.	Our TUOS unders and overs account is set out in Section 3.2.3. This section details the revenue to be recovered from TUOS charges and the unders/overs adjustment needed to move the balance of the TUOS unders and overs account to, as close as practical, zero.

Obligation	Demonstration of compliance in this Pricing Proposal
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.	Our jurisdictional scheme unders and overs account is set out in Section 3.3.4. This section details the jurisdictional scheme amount we expect to recover from customers and the unders/overs adjustment needed to move the balance of the jurisdictional scheme unders and overs account to, as close as practical, zero.
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.	Our compliance with this obligation is dealt with in Sections 2.3 and 4.2.
Apply the public lighting formula set out in Figure 16.1 of Attachment 16 of the Distribution Determination to determine public lighting charges.	Our compliance with the public lighting formula is demonstrated in Attachment 4.
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.	Our compliance with the fee based ancillary network services formula is demonstrated in Attachment 4. Note Ergon Energy has calculated prices for our fee based services using the cost build-up formula for quoted services and the fee based ancillary network services formula. For each fee based service, the price proposed in this Pricing Proposal is the lower of these two amounts.
Apply the quoted services formula set out in Figure 16.3 of Attachment 16 of the Distribution Determination to determine prices for quoted services.	Our compliance with the quoted services formula, for our illustrative examples, is demonstrated in Attachment 4. 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.	Our compliance with the price cap formula for Default Metering Services is demonstrated in Attachment 4.

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.[51]
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.
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.

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

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).
Attachment 1 – Confidential Analysis and Workings for 2017-18 Pricing Proposal "Attachment 1_Confidential analysis and workings for 2017-18 Pricing Proposal.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	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).
				is available. We provide the spreadsheet with relevant links to confidential material to allow the AER to review workings and analysis.		
Attachment 4 – Alternative Control Services pricing models "ACS pricing inputs" Page 1 (Inputs) rows 15-25, 35-48 and 59-72 (labour) Page 1 (Inputs) rows 80-101 (fleet)	Labour rates (base and inclusive of on-costs and overheads) and fleet rates (base and inclusive of overheads)	Alternative Control Services pricing	Market sensitive cost inputs	This is commercially sensitive information which provides the costs of Ergon Energy undertaking work itself (i.e. internal labour and fleet costs). The AER agreed to our request to treat this information as confidential information during the 2015–20 Distribution Determination process. Therefore, this information should be kept confidential for the remainder of this period.	If publicly released, this information may provide an advantage to our competitors and adversely affect the market for certain materials and services Ergon Energy acquires from our suppliers and contractors.	Making our input prices known to competitors may weaken any existing competitive market for similar services in some areas and would be counter to the development of competition in service delivery.

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).
Attachment 4 – Alternative Control Services pricing models "Quoted services model" Page 4 (Inputs), rows 15 to 25, 35 to 48, and 59 to 72 (labour) Page 4 (Inputs), rows 80 to 88 and 93 to 101 (fleet) Page 5 (Assumptions), rows 14 to 72 (labour hours and fleet hours)	Labour rates (base and inclusive of on-costs and overheads) and fleet rates (inclusive of overheads) Assumed average total time to perform illustrative service and assumed vehicle usage (hours)	Alternative Control Services pricing	Market sensitive cost inputs	As above	As above	As above
Attachment 4 – Alternative Control Services pricing models "Fee based services model" Page 5 (Inputs), rows 15 to 25, 35 to 48, and 57 to 70 (labour) Page 5 (Inputs), rows 78 and 83 (fleet) Page 6 (Assumptions), rows 11 to 36 (labour hours)	Labour rates (base and inclusive of on-costs and overheads) and fleet rates (inclusive of overheads) Assumed average travel time, time on the job and total time (hours)	Alternative Control Services pricing	Market sensitive cost inputs	As above	As above	As above

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).
Attachment 5 – Supporting material for ROLR adjustments in Unders and Overs accounts "5b_EECL Statement of charges for GoEnergy"" Page 2 (data), rows 4-461	NMIs and retail billing data.	ROLR adjustments in Unders and Overs accounts	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.	This is private information relating to individual customers and retailers. The publication of this information would breach the NER.	We expect consumers would have an expectation that this information would not be released to the public by a third party.

Table A4.2: Proportion of confidential material

Submission Title	Number of pages of submission that include information subject to a claim of confidentiality	Number of pages of submission that do not include information subject to a claim of confidentiality	Total number of pages of submission	Percentage of pages of submission that include information subject to a claim of confidentiality	Percentage of pages of submission that do not include information subject to a claim of confidentiality
2017–18 Pricing Proposal (PDF document)	0	101	101	0%	100%
Attachment 1: Confidential analysis and workings for 2017-18 Pricing Proposal (Excel)	31	0	31	100%	0%
Attachment 2: Revised indicative pricing schedule (PDF document)	0	32	32	0%	100%
Attachment 3: Differences between indicative and proposed 2017-18 prices (Excel)	0	11	11	0%	100%
Attachment 4: Alternative Control Services pricing models (Excel)	5	19	24	21%	79%
Attachment 5: Supporting material for ROLR adjustment in unders and overs accounts (PDF document and Excel)	1	29	30	3%	97%
Total	**37**	**192**	**229**	**16%**	**84%**

Note: This notice is an approximate indication of the proportion and comparative proportion of material in Ergon Energy's 2017-18 Pricing Proposal (including its attachments and appendices) that is subject to a claim of confidentiality compared to that which is not.

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