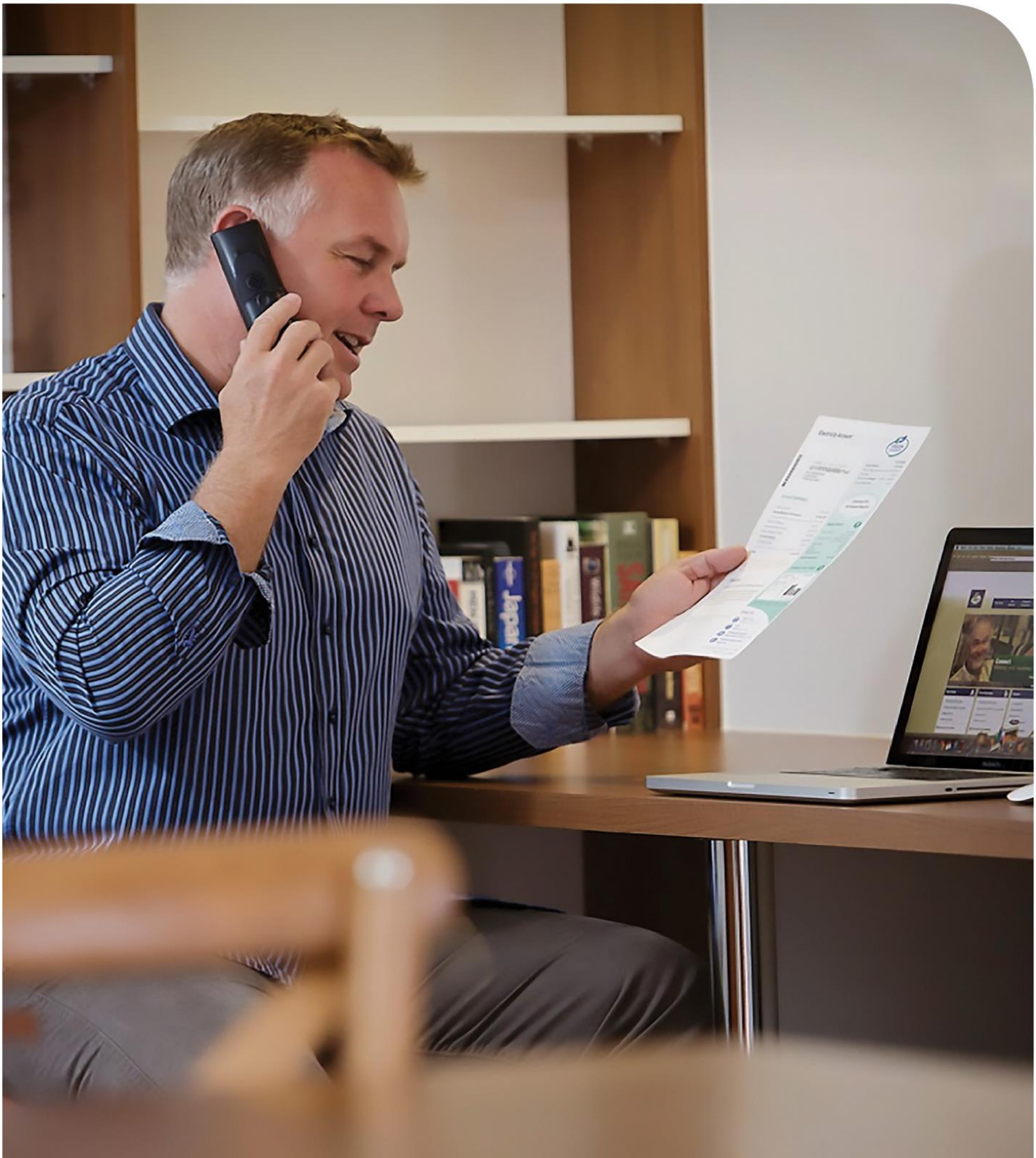

Revised Tariff Structure Statement 2017 to 2020

October 2016

Contents

1. Introduction

1.1 Background

Ergon Energy Corporation Limited (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

In November 2014, amendments to the National Electricity Rules (NER) fundamentally changed the framework in which network tariffs are developed. These changes included obligations on 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.

This Tariff Structure Statement (TSS) is part of this new framework. The TSS aims to transparently show how Ergon Energy applies the new pricing principles to develop our price structures for Direct Control Services. It also provides indicative annual tariffs for the 2017 to 2020 period. The approved TSS will remain in place for the regulatory control period.[1]

The TSS interfaces with Ergon Energy's Pricing Proposal, which is submitted each year for approval by the Australian Energy Regulator (AER). Each Pricing Proposal must be consistent with the approved TSS. However, actual rates in the Pricing Proposal are expected to differ from the indicative schedules provided in the TSS. We will explain the reasons for these differences in the relevant Pricing Proposal.

1.3 Scope of the Tariff Structure Statement

1.3.1 Direct Control Services

Consistent with the NER, this TSS covers Ergon Energy's Direct Control Services.[2] There are two types of Direct Control Services:

- Standard Control Services (SCS) – what customers see as their ongoing day-to-day access and use of the distribution network
- Alternative Control Services (ACS) – user-specific distribution services.

Each of these is described further in Table 1 below.

Table 1: Direct Control Services

Direct Control Services	Description	Examples of services	Cost recovery
SCS	Core distribution services associated with the access and supply of electricity to all	• Network services (e.g. construction, maintenance and repair of the network)	• Distribution Use of System (DUOS) charges

[1] Due to transitional arrangements, this TSS covers 2017-18 to 2019-20 only.
[2] NER, clause 6.18.1A. Direct Control Services are distribution services that are subject to direct regulatory oversight by the AER through a price or revenue setting.

Direct Control Services	Description	Examples of services	Cost recovery
	customers	• Small customer connections • Type 7 metering services	
ACS	Other distribution services requested by a customer, retailer or appropriate third party	• Fee based services (e.g. de-energisations) • Quoted services (e.g. major customer connections) • Default Metering Services (Type 5 and 6 meters) • Public Lighting Services	• User-specific charges that are directly levied on the party to whom the service is being provided

Our TSS has been structured to address SCS and ACS separately, as the methodologies underlying the development of each are fundamentally different.

1.3.2 Mount Isa distribution system

In addition to our grid-connected network, the AER is responsible for the economic regulation of the Mount Isa–Cloncurry isolated network owned by Ergon Energy.[3] Under the NER, Ergon Energy must provide a separate TSS if we own, control or operate more than one distribution system, unless the AER otherwise determines.[4]

On 23 September 2015, Ergon Energy informed the AER of our intention to submit one TSS, which encompasses both the grid-connected network and the Mount Isa–Cloncurry network. The AER endorsed this approach on 9 November 2015.

1.4 Application of the Tariff Structure Statement

Ergon Energy submitted an initial TSS for the AER's consideration on 27 November 2015. The AER released its Draft Decision on our TSS on 2 August 2016. This TSS (the revised TSS) incorporates a number of minor updates to the initial TSS and addresses matters raised by the AER in its Draft Decision. We have also restructured sections of our initial TSS and associated attachments and appendices to reflect the format requested by the AER.

Ergon Energy has also developed a separate attachment to accompany this TSS – *Supporting Information - Revised Tariff Structure Statement.* The purpose and scope of these documents are outlined in Figure 1.

[3] *Electricity National Scheme (Qld) Act 1997*, section 10.
[4] NER, clause 6.8.2(e) (as amended by transitional clause 11.73.2(a)).

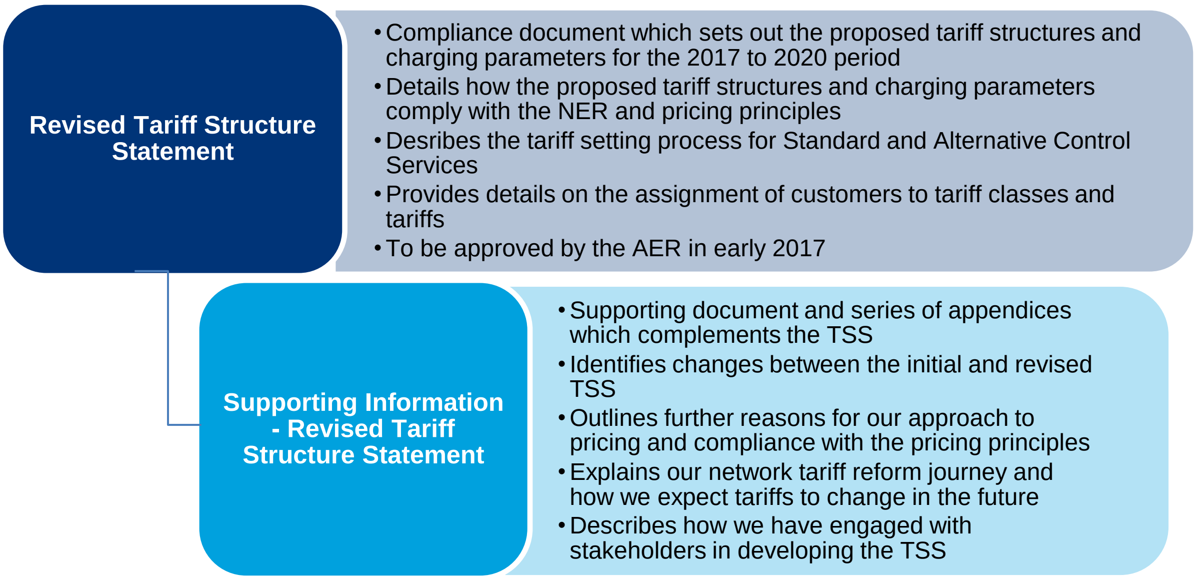

Figure 1: Revised TSS and attachments

Part 1 – Overview of Compliance Obligations

2. Compliance matrix

Ergon Energy's compliance with the NER is set out in our TSS. For ease of reference, a summary of the obligations and how we have demonstrated compliance in this TSS is provided below.

Part E: Regulatory proposal and proposed Tariff Structure Statement (TSS)

6.8.2 Submission of Tariff Structure Statement		
Clause	Requirement	Relevant TSS Section
6.8.2(a) As amended by clause 11.73.2(a)	A *Distribution Network Service Provider* must, whenever required to do so under paragraph (b), submit to the *AER* a proposed *tariff structure statement* related to the *distribution services* provided by means of, or in connection with, the *Distribution Network Service Provider's distribution system*.	Noted
6.8.2(b) As amended by clause 11.73.2(a)	A proposed *tariff structure statement* must be submitted by 27 November 2015.	Noted. Ergon Energy submitted an initial TSS on 27 November 2015.
6.8.2(c) As amended by clause 11.73.2(a)	A proposed *tariff structure statement* must be accompanied by information that contains a description (with supporting materials) of how the proposed *tariff structure statement* complies with the *pricing principles for direct control services*.	TSS: Chapter 2
6.8.2(c1a) As amended by clause 11.73.2(a)	The proposed *tariff structure statement* must be accompanied by an overview paper which includes a description of how the *Distribution Network Service Provider* has engaged with *retail customers* and *retailers* in developing the proposed *tariff structure statement* and has sought to address any relevant concerns identified as a result of that engagement.	Noted. Ergon Energy submitted an overview paper with our initial TSS on 27 November 2015. Further information on our stakeholder engagement is available in our *Supporting Information – Revised TSS* document.
6.8.2(d1)	The proposed *tariff structure statement* must be accompanied by an *indicative pricing schedule*.	TSS: Appendix A and B
6.8.2(d2)	The proposed *tariff structure statement* must comply with the *pricing principles for direct control services*.	TSS: Chapters 6 and 12

6.8.2(e) As amended by clause 11.73.2(a)	If more than one *distribution system* is owned, controlled or operated by a *Distribution Network Service Provider*, then, unless the *AER* otherwise determines, a separate *tariff structure statement* is to be submitted for each *distribution system*.	In addition to our grid-connected network, the Australian Energy Regulator (AER) is responsible for the economic regulation of the Mount Isa–Cloncurry isolated network owned by Ergon Energy. On 9 November 2015, the AER advised that it agreed with our proposal to submit one TSS covering the grid-connected network and the Mount Isa–Cloncurry network.

6.10.3 Submission of Revised Tariff Structure Statement		
Clause	Requirement	Relevant TSS Section
6.10.3 (a) As amended by clause 11.73.2(a)	In addition to making written submissions, the *Distribution Network Service Provider* may, not more than 45 business days after the publication of the draft determination on the proposed *tariff structure statement*, submit a revised proposed tariff structure statement to the AER.	Noted
6.10.3 (b) As amended by clause 11.73.2(a)	A *Distribution Network Service Provider* may only make the revisions referred to in paragraph (a) so as to incorporate the substance of any changes required to address matters raised by the draft determination on the proposed *tariff structure statement* or the *AER's* reasons for it.	Noted. A summary of changes made between our initial and revised TSS is available in the *Supporting Information – Revised TSS* document.
6.10.3 (b1)	A revised proposed *tariff structure statement* must comply with the *pricing principles for direct control services* and must be accompanied by a revised *indicative pricing schedule*.	TSS: Chapters 6 and 12, and Appendix A and B.

Part I: Distribution pricing rules

6.18.1A Tariff Structure Statement		
Clause	Requirement	Relevant TSS Section
6.18.1A(a)(1)	A *tariff structure statement* must include the *tariff classes* into which *retail customers* for *direct control services* will be divided during the relevant *regulatory control period*.	TSS: Section 5.1 and 10.1
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).	TSS: Appendix D and E

6.18.1A(a)(3)	A *tariff structure statement* must include the structures for each proposed tariff.	TSS: Sections 5.2 to 5.8 and Sections 10.2 to 10.5
6.18.1A(a)(4)	A *tariff structure statement* must include the *charging parameters* for each proposed tariff.	TSS: Sections 5.2 to 5.8 and Sections 10.2 to 10.5
6.18.1A(a)(5)	A *tariff structure statement* 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.	TSS: Chapters 4 and 11
6.18.1A(b)	A *tariff structure statement* must comply with the *pricing principles for direct control services*.	TSS: Chapters 6 and 12
6.18.1A(c)	A *Distribution Network Service Provider* must comply with the *tariff structure statement* approved by the *AER* and any other applicable requirements in the *Rules*, when the provider is setting the prices that may be charged for *direct control services*.	Noted
6.18.1A(d)	Subject to clause 6.18.1B, a *tariff structure statement* may not be amended during a *regulatory control period*.	Noted
6.18.1A(e)	A *tariff structure statement* must be accompanied by an *indicative pricing schedule* which sets out, for each tariff for each *regulatory year* of the *regulatory control period*, the indicative price levels determined in accordance with the *tariff structure statement*.	TSS: Appendix A and B
6.18.3 Tariff classes		
Clause	Requirement	Relevant TSS Section
6.18.3(b)	Each customer for *direct control services* must be a member of 1 or more *tariff classes*.	Tariff classes are discussed in Sections 5.1 and 10.1 of our TSS. Compliance with this clause will be demonstrated in our annual Pricing Proposal.
6.18.3(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*).	Tariff classes are discussed in Sections 5.1 and 10.1 of our TSS. Compliance with this clause will be demonstrated in our annual Pricing Proposal.
6.18.3(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.	Tariff classes are discussed in Sections 5.1 and 10.1 of our TSS. Compliance with this clause will be demonstrated in our annual Pricing Proposal.

6.18.4 Principles governing assignment or re-assignment of retail customers to tariff classes and assessment and review of basis of charging		
Clause	Requirement	Relevant TSS Section
6.18.4(a)	In formulating provisions of a distribution determination governing the assignment of *retail customers* to *tariff classes* or the re-assignment of *retail customers* from one *tariff class* to another, the *AER* must have regard to the following principles:	TSS: Appendix D
	(1) *retail customers* should be assigned to *tariff classes* on the basis of one or more of the following factors: (i) the nature and extent of their usage; (ii the nature of their *connection* to the *network*; (iii) whether remotely-read interval metering or other similar metering technology has been installed at the *retail customer's* premises as a result of a *regulatory obligation or requirement*;	TSS: Appendix D
	(2) *retail customers* with a similar *connection* and usage profile should be treated on an equal basis;	TSS: Appendix D
	(3) however, *retail customers* with micro-generation facilities should be treated no less favourably than *retail customers* without such facilities but with a similar load profile;	TSS: Appendix D
	(4) a *Distribution Network Service Provider's* decision to assign a customer to a particular *tariff class*, or to re-assign a customer from one *tariff class* to another should be subject to an effective system of assessment and review. **Note:** If (for example) a customer is assigned (or reassigned) to a *tariff class* on the basis of the customer's actual or assumed *maximum demand*, the system of assessment and review should allow for the reassignment of a customer who demonstrates a reduction or increase in *maximum demand* to a *tariff class* that is more appropriate to the customer's *load* profile.	TSS: Appendix D and Appendix E
6.18.4(b)	If the *charging parameters* for a particular tariff result in a basis of charge that varies according to the usage or load profile of the customer, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which a customer is charged.	Noted. Consistent with Attachment 14 of the Distribution Determination, we will address this in each Pricing Proposal.
6.18.5 Pricing principles		
Network pricing objective		
Clause	Requirement	Relevant TSS Section

6.18.5(a)	The *network pricing objective* is that the tariffs that a *Distribution Network Service Provider* charges in respect of its provision of *direct control services* to a *retail customer* should reflect the *Distribution Network Service Provider's* efficient costs of providing those services to the *retail customer*.	Noted
Application of the pricing principles		
Clause	Requirement	Relevant TSS Section
6.18.5(b)	Subject to paragraph (c), a *Distribution Network Service Provider's* tariffs must comply with the pricing principles set out in paragraphs (e) to (j).	TSS: Chapters 6 and 12
6.18.5(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) 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).	TSS: Chapters 6 and 12
6.18.5(d)	A *Distribution Network Service Provider* must comply with paragraph (b) in a manner that will contribute to the achievement of the *network pricing objective*.	TSS: Sections 6.1 and 12.1
Pricing principles		
Clause	Requirement	Relevant TSS Section
6.18.5(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*.	TSS: Sections 6.2 and 12.2, and Appendix C

6.18.5(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*.	TSS: Sections 6.3 and 12.3. Additional information on our LRMC methodology is set out in our *Supporting Information – Revised TSS* document.
6.18.5(g)	The revenue expected to be recovered from each tariff must: (1) reflect the *Distribution Network Service Provider's* total efficient costs of serving the *retail customers* that are assigned to that tariff; (2) when summed with the revenue expected to be received from all other tariffs, permit the *Distribution Network Service Provider* to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the *Distribution Network Service Provider*; and (3) comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (f).	TSS: Sections 6.4 and 12.4
6.18.5(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.	TSS: Sections 6.5 and 12.5

6.18.5(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*.	TSS: Sections 6.6 and 12.6
6.18.5(j)	A tariff must comply with the *Rules* and all *applicable regulatory instruments*.	TSS: Sections 6.7 and 12.7

Part 2 – Standard Control Services

3. Understanding network tariffs

3.1 Key concepts in tariff design

There are a number of pricing concepts discussed in this TSS. To assist understanding, we have explained these concepts below.

3.1.1 Tariff classes

We have a wide diversity of customers, in terms of their size, location, and usage patterns. We group our customers according to these characteristics. Tariff classes therefore refer to a group of customers with similar characteristics. Ergon Energy has 18 tariff classes for SCS customers. These tariff classes are detailed in Section 5.1.

3.1.2 Tariff structures, charges and charging parameters

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

Tariffs have three key defining characteristics:

- the charge (can also be called '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 charging parameters for our SCS as shown in Table 2.

Table 2: Types of charges and charging parameters

Charge	Charging Parameter
Fixed charge	Represented as a rate per day. Structures for most tariffs include a fixed charge.
Volume charge	Represented as a rate per kWh. Structures for most tariffs include a volume charge. However, different parameters apply to this charge for different tariffs. These are explained in Chapter 5. 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).

Demand charge	Represented as either a rate per kW or a rate per kVA. Most tariffs include a demand charge. Different parameters apply to this charge for different tariffs. These are explained in Chapter 5. 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).

Capacity charge	Represented as a rate per kVA. Sections 5.6 and 5.6.3 outline the application of capacity charges for our ICC and CAC tariffs.

Charge	Charging Parameter
Excess reactive power (kVAr) charges	Represented as a rate per excess kVAr. Sections 5.6 and 5.6.3 outline the application of excess reactive power charges for our ICC and CAC tariffs.
Connection unit charges	Represented as a rate per connection unit per day. Section 5.6 outlines the application of connection unit charges for our CAC tariffs.

4. Establishing tariffs for Standard Control Services

This chapter sets out the approach that Ergon Energy will take to establishing tariffs in each Pricing Proposal in 2017-18 to 2019-20.

4.1 Overview

Ergon Energy's SCS are regulated under a revenue cap form of price control. The revenue cap (or 'Total Annual Revenue') for any given year reflects Ergon Energy's smoothed revenue requirement, as determined by the AER's Post Tax Revenue Model (PTRM), plus other revenue adjustments. The resulting revenue cap is then recovered from various customer groups through network tariffs in accordance with our network tariff development process.

Designated pricing proposal charges (or Transmission Use of System (TUOS) charges) and jurisdictional scheme amounts relating to Feed-in Tariff (FiT) payments made under the Solar Bonus Scheme and the energy industry levy are then allocated to customers.

4.2 Revenue recovery in 2017–2020

Each year, Ergon Energy determines the total network (transmission, distribution and jurisdictional scheme) revenue that needs to be recovered from network users.

The revenue cap includes Ergon Energy's smoothed revenue requirement, as set out in the PTRM, plus other revenue adjustments relating to:

- the difference between forecast and actual inflation
- the return on debt[5]
- the Service Target Performance Incentive Scheme
- any cost pass through amounts associated with the occurrence of any prescribed or nominated pass through events
- unders and overs associated with the DUOS unders and overs account.

A detailed discussion on the calculation of the revenue cap will be contained in each annual Pricing Proposal.

Ergon Energy also recovers revenues on behalf of Powerlink and other designated pricing proposal charges (see Section 4.4), and jurisdictional scheme revenue associated with FiT payments made under the Solar Bonus Scheme and the energy industry levy (see Section 4.5).

4.3 Allocation of revenue cap to user groups

The process for allocating and converting the revenue cap to each of the various network user groups is set out in Figure 2 below. Essentially, the revenue cap is allocated to three pricing zones and the zonal costs are apportioned to different asset categories within each zone. The costs within the zones are then assigned to four network user groups and converted into network tariffs that recover the costs. As noted above, TUOS and jurisdictional scheme amounts are then allocated to customers.

[5] Under the trailing average portfolio approach, the rate of return on debt, and consequently the allowed rate of return, will vary each regulatory year. As such, the PTRM and the smoothed revenue requirement are amended each year to take into account the updated allowed rate of return.

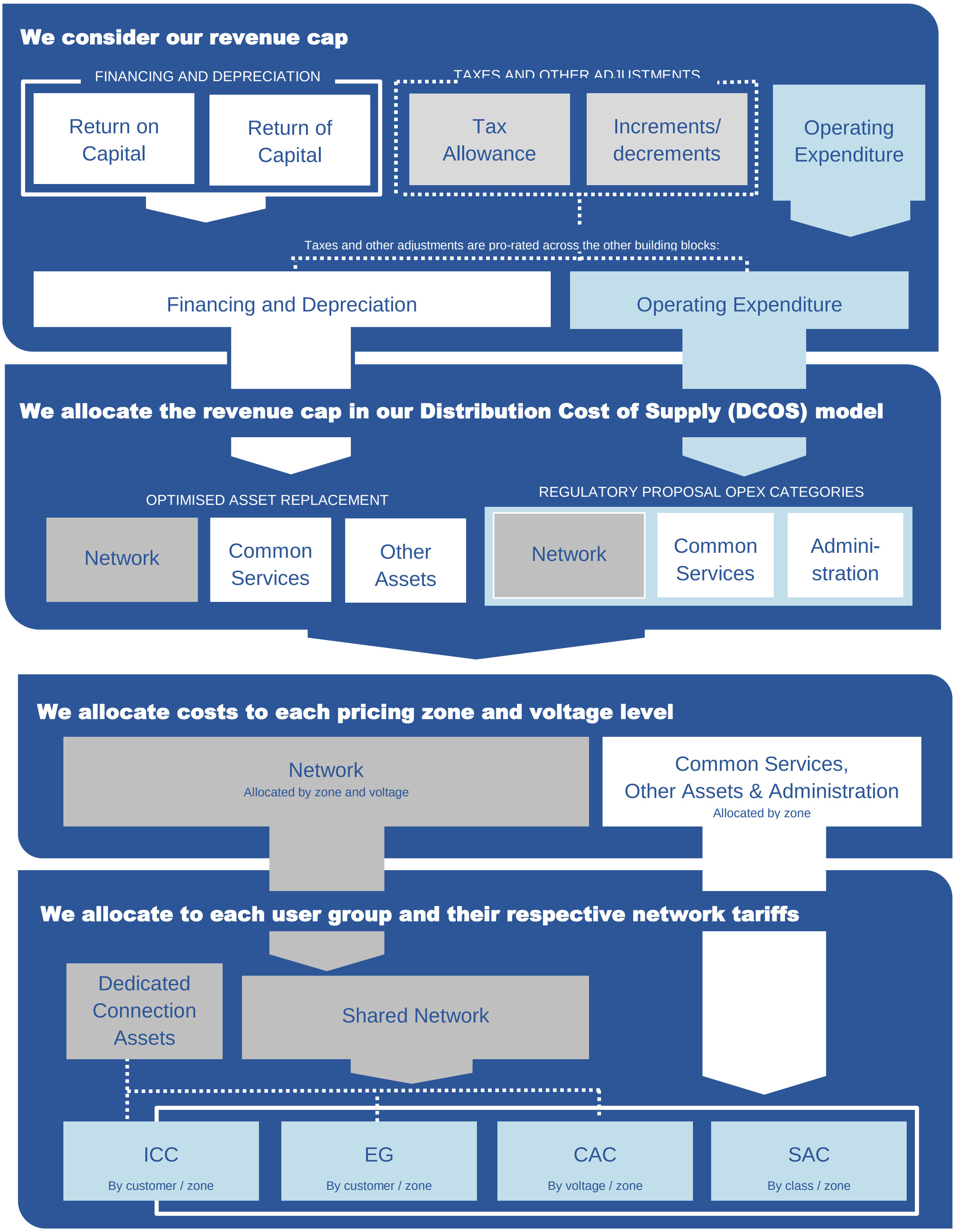

Figure 2: Allocating the revenue cap to network user groups

The following sections provide high level information on the network user groups and pricing zones. Further information can be found in Ergon Energy's *Information Guide for Standard Control*

Services Pricing which is published on our website at www.ergon.com.au/networktariffs.

Network user groups

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

- Individually Calculated Customers (ICCs)
- Connection Asset Customers (CACs)
- Standard Asset Customers (SACs)[6]
- Embedded Generators (EGs).[7]

A description of the four network user groups is provided in Table 3: Ergon Energy's network user groups below.

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

Table 3: Ergon Energy's network user groups

Network user group	Description

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

CAC	Those customers:
	• with required capacity above 1,500 kVA
	• with energy consumption typically greater than 4 GWh p.a. (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.

6 Unmetered loads such as public lights are treated as a SAC.
7 EGs may also take load from the system. The load side will be classified as an ICC, CAC, or SAC, and a separate network tariff will apply.

Network user group	Description
SAC	Typically reflects those customers with annual consumption below 4 GWh p.a. Includes customers with micro-generation facilities (such as small scale photovoltaic (PV) generators) of the kind contemplated under Australian Standard (AS) 4777.1-2005.[8] 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.
EG	Those network users that export energy into the distribution system, except for those network users with micro-generation facilities of the kind contemplated under AS4777.1-2005.[9] 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.

Pricing zones

Network pricing zones are utilised by Ergon Energy to define geographic areas of the network where costs are assessed to be broadly similar. Ergon Energy has three pricing zones:[10]

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

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

4.4 Allocation of designated pricing proposal charges

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

- charges for prescribed exit services, prescribed common transmission services and prescribed TUOS services. These charges are billed to Ergon Energy by Powerlink, the Queensland Transmission Network Service Provider

8 AS 4777.1 – 2005. This version applied at the start of our regulatory control period 2015-20 (i.e. 1 July 2015).
9 AS 4777.1 – 2005.
10 Areas supplied from isolated (remote) generation are not included in any of the below zones.

- avoided customer TUOS charges
- charges for distribution services provided by another DNSP.

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

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

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

Indicative future TUOS charges have been estimated and are included in Appendix A.

4.5 Allocation of jurisdictional scheme amounts

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

- schemes set out explicitly under clause 6.18.7A(e) of the NER. For Queensland, this includes the Solar Bonus Scheme, which obligates Ergon Energy to pay a FiT for energy supplied into our distribution network from specific micro-embedded generators[11]
- those schemes determined by the AER to be jurisdictional schemes under clause 6.18.7A(l) of the NER. One jurisdictional scheme is currently captured by this clause. On 22 March 2016, Ergon Energy's Distribution Authority was amended by the regulator to enable the Queensland Government to recover a proportion of the state's funding commitments in respect of the AEMC through an energy industry levy. The AER approved the energy industry levy as a jurisdictional scheme on 22 April 2016.

Future annual Pricing Proposals will set out how jurisdictional scheme amounts (i.e. the amount(s) we are obligated to pay under the scheme) for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those amounts.[12]

Indicative future jurisdictional scheme charges have been estimated and are included in Appendix A.

4.6 Conversion of allocated costs into tariffs and tariff structures

The network tariffs comprise a number of charges; each selected and structured to provide signals to network users about the efficient use of the network and the impact of their usage on future network capacity and costs.

In developing network tariffs, Ergon Energy has sought to have the tariff structures signal the impact that the network users will have on the network, while:

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

- managing the demand and volume variance risk
- minimising zonal boundary issues between and within network user groups
- avoiding any signals that may result in perverse outcomes.

Chapter 5 describes our tariff structures for each network user group. Our indicative pricing schedule for SCS (Appendix A) provides further explanatory information about the charging parameters within each tariff class.

Allocation of revenues to cost reflective tariff structures

In accordance with NER requirements, we have a cost reflective tariff for each network user group that applies both a LRMC signal as well as the recovery of the residual costs. Our considerations in determining our LRMC charging signals and residual recovery for each network user group, as well as the outcomes are found in the *Supporting Information – Revised TSS*.

In order to determine the appropriate residual recovery charges, Ergon Energy models the LRMC recovery for each network user group assuming all customers were subject to the cost reflective tariff. We then model the remaining revenue to be recovered and apply this to the residual component in the tariff structure consistent with the LRMC principles outlined in the *Supporting Information – Revised TSS*, but also taking into account customer impact (and our preference for customers to move to cost reflective pricing arrangements).

Allocation of revenues to legacy tariff structures

Ergon Energy allocates the remaining revenue to legacy tariff structures after the existing and estimated recovery of revenue from cost reflective tariffs are taken into account. We have noted elsewhere in the TSS that some network user groups will need to transition away from legacy tariffs in order to meet NER requirements. Nevertheless, we have attempted to restructure tariffs where possible to best meet the pricing principles set out in the NER, moving tariffs closer to the LRMC where possible as well as ensuring structures best reflect a customer's willingness to minimise distortions which would inefficiently transfer cost recovery from one customer to another.

We also take into account customer impacts of changes, ensuring that customer groups are not substantially affected by changes to tariff structures, and that outlier customers are kept to a minimum or have a cap in price movement.

5. Tariff structures

This chapter details our tariff classes and their respective network tariff structures, including charging parameters, which will apply in 2017-18 to 2019-20.

5.1 Tariff classes

Ergon Energy will continue to support 18 tariff classes for our SCS in the 2017 to 2020 period. These tariff classes are consistent with those applying in 2015-16 and 2016-17.

Our selection of SCS tariff classes aligns with our cost allocation process for tariff-setting by differentiating between:

- customer groups
  - Individually Calculated Customers (ICC)
  - Connection Asset Customers (CAC)
  - Standard Asset Customers (SAC)
    - SAC Large
    - SAC Small
    - SAC Unmetered
  - Embedded Generators (EG)
- locational zones
  - East Zone
  - West Zone
  - Mount Isa Zone.

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

Table 4 below outlines all the tariff classes by group and region.

Table 4: Ergon Energy's SCS tariff classes

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

Tariffs and tariff structures differ between customer groupings. However, there is no difference in tariff structures within a customer grouping across the pricing zones. In other words, the same tariff structures apply to CACs in the East, West and Mount Isa Zones. Only rates tend to differ between pricing zones. Because of this we are likely to engage with stakeholders on streamlining our tariff classes as part of our consultation for the TSS to apply from 2020.

5.2 Residential and small to medium business customers (SAC Small)

Ergon Energy offers a range of network tariffs to our residential and small to medium business customers who use less than 100 MWh of electricity per year. At the highest level, these network tariffs are:

- Inclining Block Tariff (IBT)
- Seasonal Time-of-Use Energy (STOUE)
- Seasonal Time-of-Use Demand (STOUD).

Like all tariff classes these network tariffs are further differentiated by the location of the customer's premises. That is:

- East, West or Mount Isa Zone
- TUOS Region 1, 2, 3 or 4.

For this customer grouping, there is also a further classification depending on whether the customer's connection is classified as residential or business (non-residential). Some of the charging parameters are different depending on this additional level of classification.

Our SAC Small tariff structures are explained in further detail below, with a complete list of network tariffs and indicative prices available in Appendix A.

It is important to note that most residential and small to medium business customers are not directly impacted by our underlying network tariffs. This is because the regulated retail tariffs (Notified Prices) for these customers are not based on Ergon Energy's network tariffs[13].

For the small percentage of customers in this class (approximately 0.4%) who are on competitive retail contracts – typically the larger business customers – the impact will depend on arrangements with the customer's retailer and how they decide to respond to our network tariffs.

5.2.1 Inclining Block Tariffs

Ergon Energy will continue to offer a three step inclining block structure for the 2017 to 2020 period. Under this tariff structure, the price per kWh increases as consumption thresholds are crossed during a metered billing period.

Ergon Energy introduced these tariffs in 2014-15 as a transitional step toward more cost reflective tariffs. We noted, at that time, that the IBT will go some way to better reflect costs when compared to our previous flat energy based tariffs (without requiring metering changes at the premises).

This is because shared network costs are largely fixed, with the exception of augmentation capital expenditure which is driven by increases in peak demand. The introduction of the IBT structure enabled the move towards higher fixed charges, while also mitigating the impact for customers with low levels of consumption.

Based on current regulatory arrangements, new connections and customers to Ergon Energy will be assigned to an IBT, unless an alternative tariff is requested. To the extent that regulatory arrangements change to allow retailers more autonomy over metering service provision,

[13] Further explanation on regulated retail prices (or 'Notified Prices') is available in our *Supporting Information – Revised TSS* document

Section 5.2.3 outlines circumstances where a customer may be assigned to a demand tariff in the first instance (with the option for them to choose an alternative tariff if they prefer). In any case, over the longer term, Ergon Energy will need to transition to a greater penetration of cost reflective tariffs and we will consult on possible transition paths as part of our 2020 TSS consultation process.

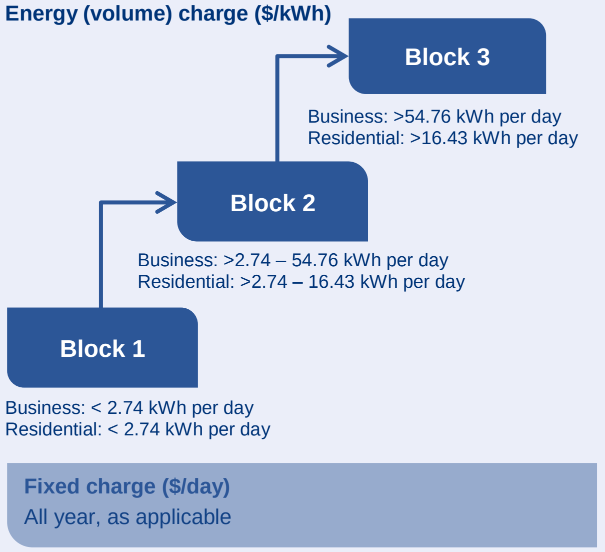
Charging parameters

The IBT is structured with a fixed charge per day and three energy consumption blocks, each with a different energy (volume) charge applicable.

The fixed charges and energy charges for each consumption block are different between the East, West and Mount Isa Zones. The block sizes and energy charges for each consumption block are also different between residential and business customers.

The IBT is denominated and applied on a daily basis. However, it may be described in the context of an annual basis for network tariff consultation and presentation purposes.[14] Daily denomination ensures IBT billing is equitably applied for any meter reading period (including instances where a customer move-out/move-in occurs) based on an accumulated total of consumption divided by the number of days in the reading period. More information on the calculation can be found in our *Network Tariff Guide for Standard Control Services*.

THE TARIFF COMPONENTS



There are four charging components for the IBT: a fixed charge and three different energy charges, which are structured into three consumption blocks (i.e. Block 1, Block 2 and Block 3).

Changes since 2015-16

To align the IBT with the Long Run Marginal Cost (LRMC) pricing principle, we have changed the rate for the first 1,000 kWh of annual consumption from zero dollars per kWh to a positive rate that is consistent with progressively reflecting the LRMC as an annualised volume rate.

The increase in the rate for the first IBT consumption block will avoid, in the first instance, the need to increase the fixed charge. This will result in a lower customer impact for low consumption customers (<1,000 kWh p.a.), than recovery of the equivalent revenue in the fixed charge.

This change in 2016-17 will be the first step in a transitional process that is expected to be largely completed in 2017-18.

5.2.2 Seasonal TOU Energy tariffs (STOUE)

In 2014-15, SAC Small customers were given the option to move to a time-of-use (TOU) energy-based tariff. Similar tariffs are currently used elsewhere in Australia. However, our offer includes seasonal and time-of-day dimensions that mirror regional Queensland's unique seasonal

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[14] For example, the annual equivalent of Block 1 is <1,000 kWh p.a.

loads (hence the name, Seasonal Time-of-Use Energy or STOUE).

The times of day when higher peak charges apply reflect the times when the network is more likely to experience peak demand conditions. In Ergon Energy's case, this is on all days during summer months in the mid-afternoon and evening for residential customers, and from late morning to early evening on summer weekdays for business customers.

The STOUE was the first step in removing the cross subsidies and distortionary incentives for inefficient customer response that are inherent in legacy tariffs. Under this tariff structure, customers are provided lower energy prices for consumption in off-peak times, when compared to the second and third IBT consumption block rates. They are also given more visibility of the higher costs associated with consumption in peak periods compared to off-peak times (when prices are significantly lower). Therefore, STOUE tariffs are aimed at greater cost reflectivity and customer choice.

A retailer must request a tariff change to opt in to these tariffs. The benefit of the STOUE tariffs compared to demand-based tariffs is they are available without the need to upgrade to remote read metering. Nevertheless, access is subject to compliance with tariff metering and associated requirements.

Charging parameters

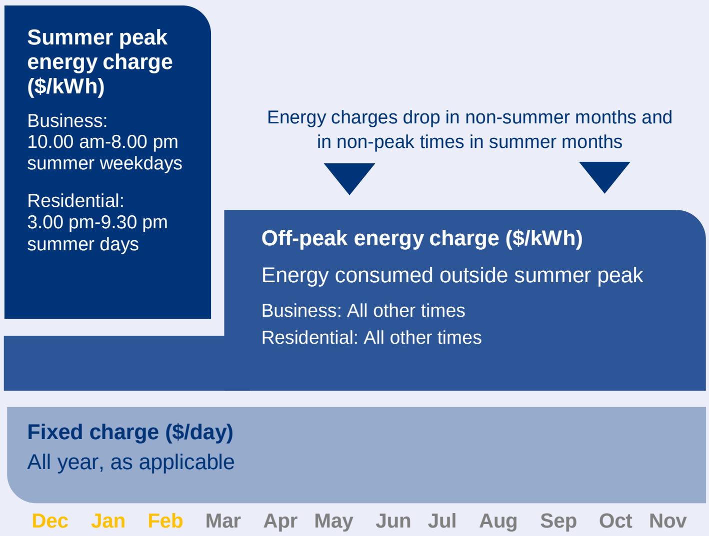
The STOUE is structured with a fixed charge per day and an energy (volume) charge which includes seasonal, day of week and time-of-day dimensions. These dimensions are based on analysis of zone substations servicing regional Queensland's business and residential load profiles across the different seasons of the year.

The rate for the energy charge for the summer peak period is higher than the energy charge for the off-peak time periods.

The peak and off-peak time periods and the energy charges for each time period are also different between residential and business customers.

The fixed charges and energy charges for each time period are also different between the East, West and Mount Isa Zones.

THE TARIFF COMPONENTS



There are three charging components for the STOUE: a peak energy charge, an off-peak energy charge and a fixed charge.

Changes since 2015-16

To align with the STOUD structure, we have consolidated the shoulder and peak energy charges (including time periods) into one peak energy charge.

This simplifies the tariff for retailers and customers and is a natural progression from our 2015-16 STOUE tariffs, where the shoulder and peak rates were the same. It also allows the LRMC charge (which has been revised higher to reflect the new LRMC pricing principle) to be applied over a longer period, reducing the LRMC rate to be applied, without diluting the signal.

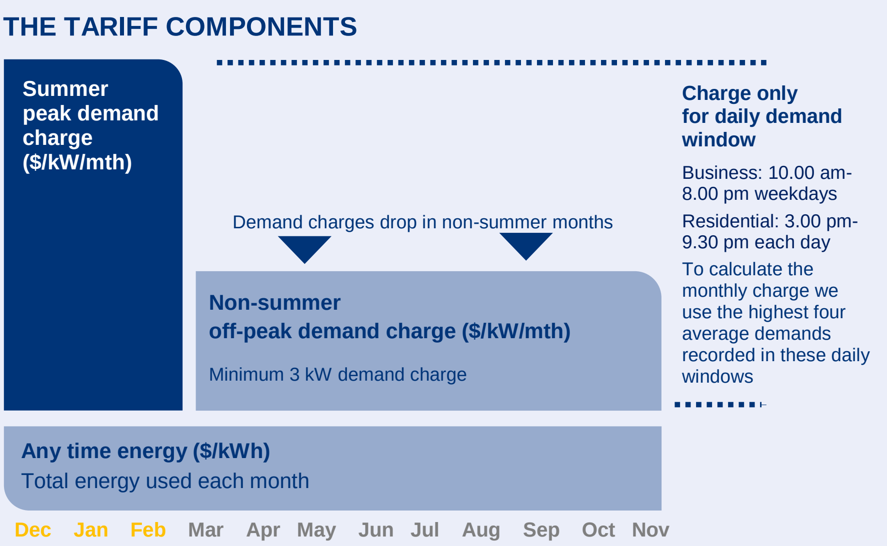
5.2.3 Seasonal TOU Demand tariffs (STOUD)

Since 1 July 2015, SAC Small customers with appropriate metering capability have had the option to choose a demand-based tariff that incorporates seasonal, day of the week and time-of-day dimensions. The structure and the rates associated with each component reflect the cost associated with placing additional demand on the network, especially in the summer months.

When compared to the STOUE, it allows us the opportunity to refine the visibility of the cost of investment at peak times even further. This, in turn, allows more favourable prices outside the peak charge periods.

Charging parameters

The STOUD is structured with demand charges and an any time energy (volume) charge.



There are three charging components for the STOUD: a peak demand charge in the summer months; an off-peak demand charge in the non-summer months; and an any time energy (volume) charge throughout the year.

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.

For business customers, the demand window is the half hours between 10.00 am and 8.00 pm on weekdays. For residential customers, the window is the half hours between 3.00 pm and 9.30 pm each day of the year.

We look at the highest four demand days in the month, determined by the average demand recorded in these daily demand windows. We apply the monthly demand rate to the average of these top four demand days.

This more moderated application of the peak charging mechanism (compared to measuring a single half hour period of maximum demand) minimises the bill impact of any abnormally high peak demand days. It also improves the likelihood of the period measured coinciding with the relevant network zone substation peak (peak demand drives our costs, so any opportunity to reduce this demand will benefit all customers).

In the non-summer months, the kW rate applied to the off-peak demand charge is much lower. The only other difference is that a 3 kW floor also applies. This means 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. This mechanism has allowed us to remove fixed charges for DUOS throughout the summer months.[15]

A flat energy charge is applied all year round.

The lower rates set in this tariff for off-peak demand and energy means real savings for customers 90% of the time, when the network is not being used to its full capacity.

At the moment a customer (via their retailer) must request a tariff change if they wish to adopt this tariff. This is subject to the provision of compliant metering. Changes to the NER may affect obligations surrounding the ownership of metering services and the availability of Type 4 metering. Depending on the outcome of these changes we may seek to apply the STOUD to all new premises connections (with installed metering capable of applying the tariff) from 1 July 2018. Even after this time customers, through their retailer, will still have the option not to have the STOUD applied to their premises and choose the alternative STOUE or IBT that we offer.

Changes since 2015-16

In response to feedback on simplifying the tariff, we have amended the calculation of the both the peak and off-peak (non-summer) demand charges. Changes were made to align the calculation of the chargeable quantity to the same approach and the same times for peak and off-peak demand, and to determine which four days were used for calculation based on the average demand over the entire daily peak period, rather than the highest four single half hour daily demands during the peak period.

We are also progressively increasing the proportion of LRMC incorporated in the peak demand charge. This will strengthen the cost reflectivity of the STOUD tariffs.

5.3 Secondary tariffs

5.3.1 Controlled load

Many customers, in addition to their primary tariff, enter into arrangements with Ergon Energy whereby some appliances are subject to a secondary “controlled tariff”. Controlled load tariffs allow Ergon Energy to directly curtail supply to designated circuits at a customer’s premises in return for a lower tariff than the ones applying to uncontrolled load.

Ergon Energy offers two controlled load tariffs:

- Volume Controlled – applies where specified permanently connected appliances are controlled by network equipment so that supply will be available for a minimum of 18 hours per day during time periods set at the absolute discretion of Ergon Energy
- Volume Night Controlled – applies where specified permanently connected appliances are controlled by network equipment so that supply will be available for a minimum period of eight hours a day at the absolute discretion of Ergon Energy, but usually between the hours of 10.00 pm and 7.00 am

Charging parameters

Each of our controlled load tariffs has a fixed charge ($/day) and an any time energy (volume) charge ($/kWh).

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15 Customers will still see some fixed charges relating to jurisdictional schemes, transmission costs and retail.

Changes since 2015-16

In 2015-16, a process was started to rebalance controlled load rates so that our application of LRMC and residual cost recovery are relatively consistent between primary and secondary tariffs. Our Volume Controlled and Volume Night Controlled rates assume controlled load makes negligible contribution to peak load (as we can control the load during peak times).

We are also intending to introduce an additional controlled load tariff – Demand Controlled – which will be available in conjunction with the STOUD Residential tariff[16]. New products such as PeakSmart air-conditioning are potentially supported by this tariff. Essentially PeakSmart allows Ergon Energy to partially reduce the demand of air-conditioning at times of system peak, without significantly affecting the customer's use of the appliance. The rates for this secondary tariff take into account the network benefit associated with the reduced contribution to peak demand.

5.4 Unmetered supplies

This customer group takes supply from our network, but no meter is installed at the connection point. Unmetered supplies within our network area include public lighting, traffic lights, watchman lights and other types of unmetered public amenities (e.g. illuminated signs, phone boxes and barbeques etc.).

Charging parameters

Like controlled load, unmetered supplies comprise two charging components – fixed ($/day/device) and any time energy (volume) charges ($/kWh).

[16] The Demand Controlled tariff is not yet accessible to customers, as the associated load control products that align with calibration of the tariff are not presently available. The network tariff will be submitted for AER approval in the relevant annual Pricing Proposal once suitable load control products are available.

5.5 Commercial industrial and rural industry customers (SAC Large)

Our SAC Large customer group consists of commercial, industrial and rural industry customers who use between 100 MWh and 4 GWh of electricity a year.

Ergon Energy offers up to five types of network tariffs to these customers in each pricing zone:

- Demand High Voltage[17]
- Demand Large
- Demand Medium
- Demand Small
- STOUD.

Our SAC Large tariff structures are explained in further detail below, with a complete list of network tariffs and indicative prices available in Appendix A.

5.5.1 Demand tariffs

These general demand-based tariffs allow customers to reduce their network tariff costs by reducing peak demand and/or total energy use.

Charging parameters

Our demand tariff structures have a fixed charge, an actual demand charge and any time energy (volume) charge.

The actual demand charge is based on the maximum amount of electricity used in any one half-hour time period in the monthly billing period. It applies to the customer's actual demand above a set threshold, which varies depending on the type of tariff.

Changes since 2015-16

Ergon Energy will continue to phase out the Demand High Voltage tariffs. This tariff will only be available in the East Zone and is not available to new customers.

Possible introduction of kVA charging

As part of our network tariff strategy, we considered the introduction of kVA charging for our SAC Large customers. We recognise that this type of charging provides price signals to encourage customers to manage demand through improved power factor.

However, the introduction of kVA in the SAC Large tariff structures will not be progressed in

THE TARIFF COMPONENTS

Actual demand charge ($/kW/mth)

Applied to the kW amount by which actual monthly maximum demand is greater than the applicable demand threshold.

Threshold above which the demand charge applies:

Demand High Voltage – 400 kW
Demand Large – 400 kW
Demand Medium – 120 kW
Demand Small – 30 kW

Fixed charge ($/day)

All year, as applicable

Any time energy ($/kWh)

Total energy consumed

There are three charging components for the general demand tariffs: an actual demand charge, a fixed charge and an any time energy charge.

[17] East Zone only.

the current TSS period. This is because the most common approach to implement power factor improvement solutions can interact with inverter system connections in an adverse way and create a need for investment to maintain voltage control. We will consult with stakeholders further on this issue as part of the development of the TSS applying from 2020.

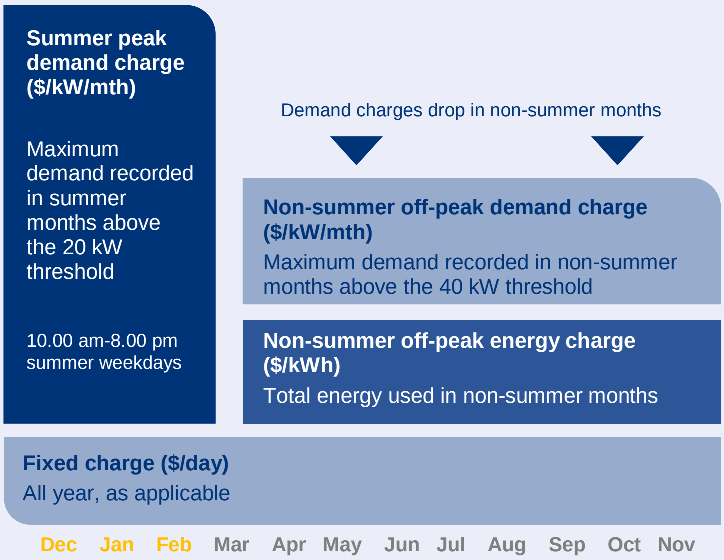
5.5.2 Seasonal TOU Demand tariffs

Since 1 July 2015, SAC Large customers with appropriate metering capability have had the option to choose a STOUD tariff. Like the STOUD for SAC Small customers, the structure and the rates associated with each component reflect the cost associated with placing additional demand on the network, especially in the summer months. It provides the opportunity for savings for customers for 90% of the time, when the network is not being used to its full capacity.

A customer (via their retailer) must request a tariff change to opt in to these tariffs. This is subject to the provision of tariff compliant metering.

Given the tariffs for SAC Large customers are usually self-selecting, our preference would be, from July 2017, for new premises and customers moving into existing premises for this customer group (with the required metering) to be subject to this tariff (with the option of choosing the general demand tariffs if desired).

THE TARIFF COMPONENTS



There are four charging components for the STOUD: a peak demand charge in the summer months, an off-peak demand charge in the non-summer months, an off-peak energy charge and a fixed charge.

Charging parameters

The STOUD has peak and off-peak demand charges, an off-peak energy charge and a fixed charge.

Unlike the average demand peak charge for residential and small to medium business customers, the summer peak demand charges for this customer group are based on the monthly maximum demand recorded in any single half hour between 10.00 am and 8.00 pm on a summer weekday (December, January and February). This monthly demand charge is applied to the kW amount by which this monthly maximum demand exceeds 20 kW (the demand threshold applicable to the peak period).

Similarly, for non-summer months, a demand charge will be applied to the kW amount by which the recorded monthly maximum demand exceeds 40 kW. This demand may occur at any time during the month (i.e. it is not limited to between 10.00 am and 8.00 pm on a weekday). Obviously, where the monthly metered maximum demand is less than the demand threshold, the chargeable demand for that month is set to zero.

An energy charge is applied to all energy consumed in non-summer months. The fixed charge also applies throughout the year.

Changes since 2015-16

We are progressively increasing the proportion of LRMC incorporated in the peak demand charge. This will strengthen the cost reflectivity of the STOUD tariffs.

5.5.3 Potential tariff for alternate supplies

Ergon Energy notes that we are considering options for the treatment of distribution charges where a customer has more than one connection to the network (alternate supply).

An alternate supply to a customer's premise may arise from local circumstances and may also be configured and operated in a variety of ways. These different circumstances impose different capital and operational costs on the network for the provision of the alternate supply.

Our analysis suggests that existing customers receive alternate supplies at less cost than that imposed on the network to provide the necessary capacity reservation. We are therefore considering establishing a more cost reflective charging arrangement where an existing SAC Large customer requests an alternate supply. Transitional arrangements may be required to move customers to more cost reflective charges.

We will not make changes for this TSS but we will look to undertake further analysis and stakeholder consultation with a view to establishing any new tariff structures (if required) in the next regulatory control period 2020-25.

5.6 Large commercial and industrial customers (CAC)

Typically customers in this group include large industrial sites, large mining, manufacturing and farming operations, sugar mills, large shopping centres, hospitals, universities, correctional centres, defence force bases and large pumping stations.

Prior to 1 July 2015, each customer in this group was priced individually to take into account their relative share of asset use and the assets built for their specific connection. In response to feedback over the need for more simplicity and transparency, we introduced changes in 2015-16 to reduce the number of tariffs and individual calculations.

This resulted in the introduction of:

- four standardised tariffs in each pricing zone:
  - CAC 22/11 kV Line
  - CAC 22/11 kV Bus
  - CAC 33 kV
  - CAC 66 kV
- a connection unit charge comprised of a standard daily fixed charge that is applied against each customer's individual number of connection units[18]. This effectively maintains a connection charge per customer which is reflective of the connection assets dedicated to them.

Consistent with our general direction to look at what drives our costs and aligning this with our

[18] Customers connecting after 2010 have zero connection units allocated

pricing signals, we also introduced the following optional STOUD tariffs:

- STOUD CAC 22/11 kV Line
- STOUD CAC 22/11 kV Bus
- STOUD CAC Higher Voltage (66/33 kV).

Our CAC tariff structures are explained in further detail below, with a complete list of network tariffs and indicative prices available in Appendix A.

5.6.1 CAC standardised tariffs

Charging parameters

Our standardised CAC tariff structures have six charging parameters.

The actual demand charge is based on the maximum amount of electricity used in any one half-hour time period in the monthly billing period. It applies to the customer's actual demand (kVA).

The excess reactive power (kVAr) charge is calculated monthly based on the power factor recorded 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 NER compliant power factor), excess kVAr charges are applied.

The capacity charge is applied to the customer's individual kVA authorised demand or, if there is no authorised demand, the annual maximum demand in the previous full pricing period prior to the setting of prices[19].[20] Where the actual demand exceeds the authorised demand in any one month, the actual demand will be substituted for the authorised demand in the calculation of the capacity charge for that month.

The connection unit charge is multiplied by the customer's number of connection units. For customers that connected to the network on or after 1 July 2015, no connection units will apply.

A fixed charge and a flat energy (volume) charge apply throughout the year.

THE TARIFF COMPONENTS

Actual demand charge ($/kVA/mth)
Applied to the actual kVA monthly maximum demand

Excess reactive power charge ($/excess kVAr/mth)
Applied against the kVAr used by a customer that exceeds the customer's permissible quantity

Capacity charge ($/kVA of Authorised Demand/mth)
Greater of the kVA authorised demand or the actual kVA monthly maximum demand

Fixed charge ($/day)
All year, as applicable

Connection unit charge ($/day per connection unit)
All year, as applicable

Any time energy charge ($/kWh)
Total energy consumed

There are six charging components for CAC standard tariffs: an actual demand charge, an excess reactive power charge, a capacity charge, a fixed charge, a connection unit charge and an any time energy charge.

[19] Under certain circumstances, where there has been a significant change in demand attributable to a network user's load change after this previous pricing period, a more recent demand may be substituted.

[20] In order to convert the authorised demand to kVA, we used a site's power factor (the ratio of real power (kW) to total power (kVA)). This was done by taking the highest power factor from a premises' most recent 12 months of meter data at the monthly peak in demand. Ergon Energy will review this each year.

Changes since 2015-16

We have introduced an excess reactive power charge or excess kVAr charge[21]. This charge reinforces the price signal introduced by the kVA tariff in 2015-16, which encourages customers to improve their power factor and reduce their usage of network capacity.

It will replicate the charge currently applied to ICCs when a customer's demand for kVArs exceeds a permissible quantity[22] which is specific to each customer.

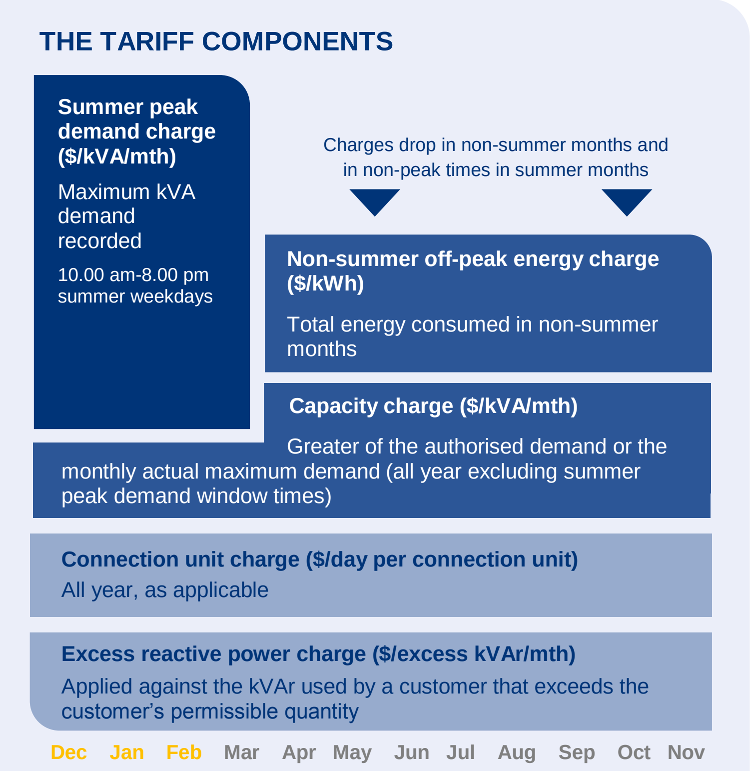
5.6.2 CAC Seasonal TOU Demand tariffs

Charging parameters

Like our other STOUD tariffs, our CAC STOUD tariff structure includes a peak demand charge, a capacity charge (off-peak demand) and an off-peak energy charge. However, the manner in which the demand charges apply is different.

The peak demand charge is based on the customer's monthly maximum kVA demand during the peak period in each summer month. The capacity charge is based on the greater of the customer's authorised demand and the actual monthly half hour maximum demand. The capacity charge applies for all 12 months of the year. Over the summer months, it excludes demand occurring during the peak demand window of 10.00 am to 8.00 pm on summer weekdays.

The off-peak energy charge is applied to all energy consumed in non-summer months.



There are five charging components for the CAC STOUD: a peak demand charge in summer months, a capacity charge, an off-peak energy charge in non-summer months, a connection unit charge, and an excess reactive power charge.

In addition, an excess reactive power charge and connection unit charge apply. These charges are calculated in the same manner as the corresponding charges in the standardised CAC tariffs.

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21 We intended to introduce an excess kVAr charge in 2016-17 for our CAC network tariffs. Our 2016-17 Pricing Proposal was amended on 30 May 2016 to defer this introduction to 1 July 2017 (subject to AER approval). The excess kVAR charging component is billed at a $0.00 rate in 2016-17.

22 Permissible quantity is calculated with reference to the customer's authorised demand and the minimal compliant power factor as specified in the NER.

Changes since 2015-16

We have made the following changes:

- The peak demand charge is no longer based on the greater of the authorised demand and monthly maximum demand during the peak period.
- The capacity charge is no longer charged on the greater of a monthly floor and the monthly maximum demand during the non-summer months.

We have also introduced a new excess reactive power charge[23], consistent with changes made to the standardised CAC tariffs.

We are confident that this structure will improve incentives for CACs to respond to the LRMC signal.

5.6.3 Potential tariff for alternate supplies

As noted in section 5.5.3, Ergon Energy is considering options for the treatment of distribution charges where a customer has more than one connection to the network (alternate supply). Similar to SAC Large customers, we are considering establishing a more cost reflective charging arrangement where an existing or new CAC requests an alternate supply.

We will not make changes for this TSS but we will look to undertake further analysis and stakeholder consultation with a view to establishing any new tariff structures (if required) in the next regulatory control period 2020-25.

[23] The introduction of the excess kVAr charge for our CAC network tariffs has been deferred until 1 July 2017 (subject to AER approval). The excess kVAR charging component is billed at a $0.00 rate in 2016-17

5.7 Individually Calculated Customers (ICC)

Customers in our ICC network user group generally use more than 40 GWh of electricity per year and comprise large coal mining customers and customers involved in other types of mining, transport (rail) and pumping operations.

Charging parameters

Our ICC network tariffs are comprised of a fixed charge, a capacity charge, an actual demand charge, an excess reactive power charge and a volume charge.

The actual demand charge is based on the maximum amount of electricity used in any one half-hour time period in the monthly billing period.

The capacity charge is applied to the customer's individual kVA authorised demand.

THE TARIFF COMPONENTS

Actual demand charge ($/kVA/mth)
Applied to the actual kVA monthly maximum demand

Excess reactive power charge ($/excess kVAr/mth)
Applied against the kVAr used by a customer that exceeds the customer's permissible quantity

Capacity charge ($/kVA of Authorised Demand/mth)
Applied to the customer-specific kVA authorised demand

Fixed charge ($/day)
All year, as applicable

Any time energy charge ($/kWh)
Total energy consumed

There are five charging components for ICC tariffs: an actual demand charge, an excess reactive power charge, a capacity charge, a fixed charge and an any time energy charge.

For these types of customers, the premises' power factor is important. Distribution systems must be designed to supply the actual power required and a low power factor means actual power delivered will be unnecessarily high. The excess reactive power charge encourages customers to improve their power factor and reduce their peak network capacity requirements.

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.

A fixed charge and a flat energy (volume) charge apply throughout the year.

Changes since 2015-16

We reviewed the current ICC tariff structure with respect to alignment with the LRMC pricing principle and concluded that the existing structure is consistent with the LRMC pricing principle. Therefore, no changes have been made.

Future improvements

In looking at options for improving LRMC signals for this tariff class, we believe there may be opportunity to improve the signal a customer receives for exceeding their authorised demand. Our analysis suggests that introducing an excess demand charge, where demand exceeds the customer's authorised demand, may be a way to improve this signal.

We have also looked at possible changes aimed at ICCs reducing their authorised demand, reducing their contribution to shared network costs via their capacity charge and actual demand charge even though the reduction will do little to reduce Ergon Energy's avoidable costs (as these costs are largely sunk).

We will not make changes for this TSS but we will look to engage with customers on this option with a view that this could be introduced in the regulatory control period 2020-25.

5.8 Embedded Generators (EG)

EGs are those network users that export into our distribution system (other than micro-embedded generators with inverters of the kind contemplated under AS 4777.1 – 2005).

Charging parameters

The NER specifically prohibit DUOS charges being applied for the export of electricity generated by the user into the distribution network.

For those EGs that generate into the distribution system, a fixed charge ($/day) applies. This charge recovers the costs associated with connection assets and network user management services provided to this customer group.

Similarly, a fixed charge applies to the generation side of those EGs that generate into, as well as take load from the distribution system. In addition, DUOS tariffs for the load side apply. These tariffs are allocated as per the appropriate network user group (i.e. ICC, CAC or SAC).

Changes since 2015-16

No changes have been made to the tariff structures for EGs since 2015-16. However we have made the following changes which impact certain EGs:

- New business rules apply for EGs who are also classified as an ICC (or CAC) for their load connection. We have observed that, when charging for the ICC load, the kVA and kVAr component may contain a contribution from the generator. This has the potential to increase the total kVA and excess kVAr billing quantities. It is not the intent of load side kVA charging for demand and excess kVAr to include this generator impact. Therefore, from 2016–17, for the purposes of network billing for loads, we will set export kVAr to zero in any interval when kW are imported into our distribution network.
- We have amended our EG (and SAC) network user definition which reference Australian Standard (AS) 4777. This standard presently captures inverters for energy systems up to 10 kVA on single phase and up to 30 kVA on three phase. In the future, AS 4777 may include inverters up to 200 kVA. To ensure a consistent and equitable approach across the regulatory control period, we have made reference to AS 4777.1-2005 in our EG (and SAC) network user group definitions. This is the standard that applied as at 1 July 2015. This means the generation side of micro-embedded generators with inverters between 30 kVA and 200 kVA will continue to be treated (and priced) as an EG.

Possible introduction of standardised rates for EG tariffs

In our initial TSS we noted the possibility of a need for a new tariff for certain micro-embedded generators if the AER did not agree with our proposed change to our EG (and SAC) network user group definitions (as a result of changes to AS 4777).

While the AER approved changes to our network user group definitions as part of our 2016-17 Pricing Proposal, Ergon Energy is starting to see an increase in connection application of inverters up to 200kVA. Currently our network tariffs for EGs (including those between 30 and 200kVA) are calculated on a site specific basis.

To the extent that site specific pricing of EGs becomes impractical for Ergon Energy to continue to administer in the 2017-20 regulatory control period, we propose to introduce tariffs for EGs with standardised rates. The network tariff structure would remain the same as the existing arrangement (fixed charge ($/day)). However the standardised rates would be approved and published in the relevant annual Pricing Proposal.

6. Meeting the pricing principles

This chapter addresses how our network tariffs satisfy the pricing principles contained in the NER. These pricing principles were modified by the AEMC in November 2014. In this chapter, we:

- outline the network pricing objective and consider the expectations from changes made to the NER
- explore our tariffs in the context of:
  - avoidable and stand-alone costs
  - Long Run Marginal Cost (LRMC)
- set out how our tariffs recover our allowed revenues in an efficient and least-distortionary manner
- build on our theme of affordability for customers in the context of the likely impact on retail customer bills.

6.1 Network pricing objective

Our tariffs should reflect Ergon Energy's efficient costs of providing services to customers.

The network pricing objective is that distribution network tariffs payable by a retail customer should reflect a DNSP's efficient costs of providing Direct Control Services to that customer. Under the NER, DNSPs are required to comply with the distribution pricing principles in such a way that contributes to the achievement of the network pricing objective.

In its final determination on the *Distribution Network Pricing Arrangements* rule change, the AEMC explained that:

> *The focus of the network pricing objective is cost reflectivity. Cost reflectivity in relation to network tariffs has three key components:*
>
> *(i) Sending efficient signals about future network costs.*
>
> *(ii) Allowing a DNSP to recover its regulated revenue so that it can recover its efficient costs of building and maintaining the existing network.*
>
> *(iii) Each consumer should pay for the costs caused by its use of the network.*
>
> *Taken together, these three components of cost reflectivity should result in an outcome where the network prices that each consumer faces reflect the costs that particular consumer causes through its use of the network.*[24]

[24] AEMC (2014), *Rule Determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014,* 27 November 2014, p19.

The AEMC defined cost reflectivity in the network pricing objective by reference to the very same matters that are the subject of the pricing principles. This gives rise to circularity between the objective and the pricing principles. The pricing principles themselves stress the need for tariffs to:

- be subsidy-free
- reflect LRMC
- recover the remainder of a DNSP's regulated revenue in a least-distortionary manner.

There is limited further guidance as to how Ergon Energy should satisfy the pricing principles in such a way as to contribute to the network pricing objective, beyond that tariffs must be cost reflective, in that:

- they must send efficient signals about future costs
- allow the DNSP to recover its regulated revenue
- ensure customers pay for costs they cause.

In other words, the objective does not provide any additional guidance to DNSPs about how to apply the pricing principles other than what is embodied in the principles themselves.

To overcome this circularity, Ergon Energy has chosen to interpret the network pricing objective to mean that network tariffs should meet the pricing principles in such a way that promotes economic efficiency across the three dimensions described below:

- **Productive efficiency** – is achieved when DNSPs produce their goods and services at the least possible cost. To achieve this, DNSPs must be technically efficient (produce the most output possible from the combination of inputs used) while also selecting the lowest cost combination of inputs given prevailing input prices.
- **Allocative efficiency** – is achieved where resources used to produce a set of goods or services are allocated to the user that provides the greatest benefit relative to costs. To achieve this, prices of the goods and services of DNSPs must reflect the productively efficient costs of providing those goods and services.
- **Dynamic efficiency** – reflects the need for industries to make timely changes to technology and products in response to changes in consumer tastes and in productive opportunities. This implies that customers should have incentives to invest in network alternatives, such as solar PV or demand-side response, where the costs of such alternatives are less than the costs of delivering additional power through the distribution network.

In developing the network tariffs outlined in Chapter 5, and in the future as we continue to refine our existing tariff structures, we have and will strive to apply the pricing principles in such a manner that promotes these dimensions of economic efficiency.

6.2 Avoidable and stand-alone costs

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

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

Cross subsidies between tariff classes will arise where tariffs recover revenues outside the bounds of the stand-alone and avoidable costs. This is why the pricing principles embody the need for tariffs to recover network revenues no less than the avoidable costs of serving a customer tariff class and no more than the stand-alone costs of serving a tariff class.

Ergon Energy interprets stand-alone and avoidable 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 SCS is set out in Appendix C. This appendix also demonstrates that, for each SCS tariff class containing retail customers,[25] the expected revenue in each year of the 2016-17 to 2019-20 period lies on or between the lower bound avoidable cost and the upper bound stand-alone cost.

Since the 2017-20 expected revenue is indicative only at this stage, Ergon Energy will re-calculate the avoidable and stand-alone costs each year and publish the revised calculations in the relevant annual Pricing Proposal.

6.3 Long run marginal cost

Each tariff must be based on the LRMC of providing the service to which it relates to 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:

- *the costs and benefits associated with calculating, implementing and applying that method as proposed*
- *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*
- *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 clause 6.18.5(f) of the NER now require each tariff to be “based on” the LRMC of providing the service to the retail customers assigned to that class, with the method of

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[25] 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.

calculating such cost and the manner in which that method is applied to be determined having regard to:

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

In response to the new NER obligations, Ergon Energy prepared or commissioned a number of reports, which we used to consult with customers on our approach to calculating and applying LRMC to network tariffs. These reports include:

- Consultation Paper: *Aligning Network Charges to the Cost of Peak Demand*, March 2015
- Supporting Document: *Long Run Marginal Cost Considerations in Developing Network Tariffs*, March 2015 (LRMC considerations report)
- Supporting Document: *Estimating the Average Incremental Cost of Ergon Energy's Distribution Network* by consultant, Harry Colebourn (the Colebourn report)
- *Maximum Demand Tariff Analysis Report* by consultants Energeia.

These reports explain our LRMC calculation methodology as well as how LRMC could be applied to our tariff structures and rates. The *Supporting Information – Revised TSS* consolidates many of the key elements of our LRMC calculation and application to prices which we have consulted on through the above documents. We provide an overview of the key elements below.

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. Ergon Energy's approach to implementing the greater emphasis on LRMC in the NER has been as follows:

- After consultation and consideration, we have used the Average Incremental Cost (AIC) methodology for deriving the estimates of LRMC we will apply in tariff-setting.
- Our inputs to the calculation of AIC were originally sourced from our October 2014 Regulatory Proposal and included:
  - network demand and related capital costs
  - operating and maintenance expenditure associated with demand related capital costs
  - incremental network demand
  - rate of return
  - power factor.
- We have updated some of the inputs used in our calculations (and our initial TSS), following the release of the AER's Distribution Determination in October 2015. Specifically, we have:
  - applied a real vanilla Weighted Average Cost of Capital (WACC) of 3.42 per cent, consistent with the Distribution Determination
  - replaced our proposed capital expenditure forecasts with the AER's capital expenditure allowances
  - adjusted the proportion of Connections expenditure (less capital contribution) from 100 percent to 50 per cent, in recognition that not all this expenditure is demand related.
- In applying the LRMC to tariff classes, we looked at:

    - the high-level trade-offs involved in establishing LRMC-based tariffs
    - the various tariff options for charging components and charging parameters.
- We applied a process for developing LRMC signalling structures for each tariff class based on:
    - our assessment of the extent and manner in which real world conditions diverge from the simple stylised conditions that informed our high-level thinking on applying LRMC to tariff-setting
    - our assessment of the likely economic efficiency consequences of making various compromises or trade-offs between different options
    - our assessment of practical considerations in setting efficient tariffs, such as the role and implications of distributed energy resources.
- We identified a peak period that best reflected network peak demand based on analysis of zone substation load profiles, taking into account random and systematic factors. We identified this by the major customer type associated with the substation load (residential and business).
- In accordance with the NER, we also considered the impact on retail customers when considering the transition to LRMC-based pricing and, in particular, the level of LRMC that would be passed on to customers through an LRMC-based charge.

Having undertaken the above steps, Ergon Energy's suite of tariffs now includes:

- a 'legacy tariff' or tariff structure that has been in place for many years and which reflects more compromises in respect of the signalling of LRMC than we consider ideal in the long run
- for all non-site specific tariff classes, an alternative optional tariff structure that customers can adopt through their choice of retail tariff. These 'LRMC-based tariffs' place a higher and more appropriate weight on signalling the LRMC of using the distribution network.

6.3.1 Application of LRMC to tariff-setting

SAC Small legacy tariffs

Reforms to legacy tariffs for this customer group have to date included moving from a simple fixed and energy tariff to an IBT – to facilitate an increase in the fixed charge and a reduction in the average energy tariff in a way that helps mitigate adverse customer impacts.

Our intention in the medium term is to gradually rebalance the IBT such that the first consumption block at least reflects the value of the low voltage LRMC.[26]

We expect the ongoing rebalancing of these tariffs in the manner described above will enable these tariffs to better reflect LRMC than they did previously. However, these legacy tariffs were not originally developed with economic efficiency in mind. Indeed, NERA's report for the AEMC commented that modifying flat or IBT structures to better reflect the LRMC may not, in itself, promote efficiency. They suggested that DNSPs should work towards implementing more cost reflective structures over time. Ergon Energy will therefore need to phase out these tariffs over time in order to better satisfy the pricing principles in the NER.

SAC Large legacy tariffs

Reforms to legacy tariffs for this customer group have to date included increasing the daily fixed

[26] The *Supporting Information – Revised TSS* has more details of this calculation.

charge and reducing the actual demand (kW-based) charge. A key rationale for these changes was to provide signals for network usage more in accordance with the LRMC of serving these customers.

SAC Large legacy tariffs demonstrate a greater level of cost reflectivity when compared to the legacy tariff design for SAC Small tariffs. The inclusion of a charging component based on maximum demand is an example of how these tariffs better signal the network cost implications of using the network at times of high utilisation.

Nevertheless, these legacy tariffs were also not developed with LRMC-based principles in mind. Current tariffs do not recognise the seasonal drivers of network investment. In addition, the 'self-selection' approach to charging components makes reform in each of the network charging categories – Demand Small, Medium, Large and High Voltage – quite complicated as changes to one parameter has a consequential impact on the attractiveness of other tariffs. Any movement to more LRMC-based pricing is likely to be gradual at best. It is more likely that Ergon Energy will need to phase out these tariffs over time in order to better meet our obligations under the NER.

CAC legacy tariffs

Like the SAC Large customer group, CAC legacy tariffs incorporate some element of cost reflectivity. Recent changes to these tariffs include the introduction of kVA signalling for the demand charging components. Following a delay in introduction in 2016-17, we propose to introduce an excess reactive power charge price for customers with power factor arrangements that are outside the NER criteria in 2017-18.

While there is little recognition of seasonal drivers of network investment in CAC legacy tariffs, we recognise that some CACs operate at higher levels of the network and may have more dedicated assets allocated to them. It is possible that there will be some customers in this network user group that contribute a large proportion of some shared network infrastructure. In this case the signal is likely to be more reflective of the customer's authorised demand (and less likely to be influenced by other network loads which are seasonal based). Nevertheless, we believe for the majority of customers in this network user group there will be beneficial network outcomes through a LRMC signal.

ICC legacy tariffs

The principal reason we have focused less on the application of LRMC to ICCs to date is that these customers tend to have less influence on the need for shared network investment than customers connected at lower voltages. Most ICCs utilise assets that are largely dedicated to one or more ICC and augmentation to these assets are typically agreed with Ergon Energy by contract rather than occurring as a consequence of our network reliability planning process. Accordingly, ICCs already face reasonable signals regarding the cost implications of their network usage decisions. Nevertheless, we will continue to explore options to ensure customers face LRMC signals by looking at the signals faced by customers when demand exceeds authorised demand or when changes to authorised demand are made.

6.3.2 Alternative LRMC-based tariffs for all tariff classes

In accordance with clause 6.18.5(f) of the NER, we are seeking to offer customers tariffs with structures that more closely reflect and signal the additional costs associated with meeting incremental demand at times of peak network utilisation.

Ergon Energy's CACs and SACs presently have access to several tariffs that incorporate more cost reflective structures than their default tariffs:

- CACs can choose a STOUD tariff. For this tariff, we are progressively applying the appropriate voltage-level LRMC to the peak demand charge applied over the summer peak period.
- SAC Large customers can choose a STOUD tariff. For this tariff, we are progressively applying the appropriate voltage-level LRMC to the customer's maximum demand (beyond a threshold) during peak times in each summer month.
- SAC Small customers can choose a STOUD or STOUE tariff. We are progressively applying the appropriate voltage-level LRMC to the peak charging components of both tariffs.

All of these tariffs incorporate a degree of seasonal, daily and time-based charging, which allows for sharper signalling of the LRMC at times of peak network utilisation.

The *Supporting Information – Revised TSS* provides more information on how these tariffs signal the LRMC of the network.

6.4 Revenue recovery

The revenue expected to be recovered from each tariff must:

- *reflect our total efficient costs of serving the customers assigned to that tariff*
- *when summed with the revenue expected to be received from all other tariffs, permit Ergon Energy to recover the expected revenue for the relevant services in accordance with the AER's Distribution Determination.*

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

The pricing principles 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. However, where this is necessary, tariffs should be set so as to minimise distortions to LRMC-based signals.

In order to minimise distortions, regulated revenues not recovered through LRMC-based tariff parameters should be recovered through parameters that do not vary with network usage. As explained in our LRMC considerations report, a number of options are available to recover a DNSP's residual costs. These options include:

- fixed charges ($/day)
- off-peak or any time energy charges ($/kWh)
- off-peak demand or capacity charges ($/kW demand or capacity).

Each of these options has advantages and disadvantages in terms of the distortionary signals they may provide.

Fixed charges are unlikely to send distortionary signals leading to inefficient customer response, unless they become so high that complete network bypass becomes viable for a customer. However, we note in sections below that high fixed costs can impact lower-consuming customers within each tariff class. In pursuing our objective of affordability, we need to balance the issues of distortionary signals with customer impacts.

Off-peak energy tariff charges rise with the off-peak consumption of a customer. This should have favourable distributional effects to the extent that off-peak energy consumption is correlated with customer size and financial resources. On the other hand, off-peak energy charges have some negative efficiency properties if set too high:

- Such charges will tend to inefficiently deter off-peak network usage (e.g. by high-load factor industrial customers) because the opportunity cost of such use will generally be very low.
- Customers may seek to bypass a higher off-peak energy charge through alternative sources (including solar PV). This can send distortionary price signals to customers particularly as the reduction in revenue received from those who have invested in alternative sources is not offset by a reduction in our costs, resulting in revenue recovery from customers who have not invested in alternative sources increasing.

This effect can be reduced if the off-peak energy rate is also relatively low.

An any time energy charge is likely to minimise distortion only if it is structured with LRMC signals in other components (i.e. if it is combined with a peak demand charge). With no LRMC signal complementing the any time energy charge, the tariff structure is likely to provide a distortionary price signal encouraging less use of the network with no corresponding reduction in network costs.

If an LRMC signal is present, setting an any time energy charge too high may over-signal the LRMC and create distortion in peak period consumption (i.e. customers inefficiently avoid peak period consumption with the combination of the LRMC signal and the high any time energy charge).

Off-peak demand tariff charges rise with the maximum off-peak demand of the customer. As such, they should have similar distributional and efficiency effects to off-peak energy tariffs. In general, the harm to economic efficiency caused by off-peak charges depends on both the:

- own-price elasticity of off-peak demand or consumption – the more price-elastic off-peak demand is, the larger the distortionary impact from a given off-peak tariff
- cross elasticity between off-peak and peak demand or consumption – the more willing customers are to shift off-peak consumption to peak periods, the larger the distortionary impact from a given off-peak tariff.

Off-peak demand tariffs will tend to benefit smaller customers but may inefficiently deter off-peak network usage, especially where off-peak usage is occasional or sporadic. This type of charge is less likely to create distortionary signals to invest inefficiently in solar PV compared to using off-peak energy to recovery residual revenue. However, if it is set too high it is likely to encourage the inefficient installation of storage for similar reasons described above.

In summary, tariff structures do require a fine balancing of charges so that prices can recover revenue allowances in the least distortionary way. Over-balancing recovery in tariff structures through any of the components can create distortionary signals and lead to inefficient customer response, resulting in suboptimal outcomes to some or all customers.

6.4.1 Our approach to recovery of residual costs

In establishing our tariff structures in Chapter 5, our consideration of different charging components took into account both the short term and long term responses that distortionary price signals in these tariffs could generate. This included an analysis of legacy tariffs. Where appropriate, we also balanced the need to minimise distortions with our own criteria for affordability as well as the important principles of retail customer impacts and simplicity for customers when the tariff is passed through on the retail bill.

Our analysis involved the testing of dozens of different combinations of LRMC and residual charging components. In addressing affordability for all customers, we measured the possible effects on price signals of different tariff structures and focused on those tariff combinations which demonstrated less cross subsidy and overall minimisation of community cost.

In some circumstances tariff combinations were adjusted to take into account issues of equity, simplicity and customer impact. For instance:

- Our residential and small to medium business STOUD tariffs have no fixed distribution network charge component (i.e. zero dollars per day). While a fixed charge in the tariff structure performed well in terms of revenue recovery, retail customers exhibited a preference for lower fixed charges in their final bill so Ergon Energy substituted a fixed charge rate with a higher off peak demand charge.
- Similarly, our existing residential and small to medium business STOUD tariff structures include a charging parameter for off-peak demand based on maximum monthly demand recorded. We have revised that parameter in response to customer concerns about the complexity of the existing tariff. While signalling off-peak demand across limited hours may create distortions compared to an any time maximum demand in the month, we have balanced these issues against customer concerns and perceived complexity.
- Annual demand charges scored reasonably well on a number of tariff structures. However, the application of an annual maximum demand charge can be difficult to explain to customers. On this basis, tariff structures that included annual maximum demand were not pursued.

6.5 Impact on retail customers

Ergon Energy 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 Ergon Energy considers reasonably necessary having regard to:

- *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)*
- *the extent to which retail customers can choose the tariff to which they are assigned*
- *the extent to which retail customers are able to mitigate the impact of changes in tariffs through their usage decisions.*

As noted above, we have 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.

In our *Supporting Information - Revised TSS* we noted that a core part of our strategy and commitment to customers is our need to address electricity affordability. To achieve this, we:

- have been driving hard to reduce our costs as a business
- are focusing, over the long term, on facilitating an effective market in developing an enabling platform that supports the interaction between the various parties seeking to use our network.

Our efforts to move our network prices towards a cost reflective framework over the last few years complement our other strategies pursuing affordability. From a network tariff perspective affordability is being addressed by:

- understanding the short term and long term impacts of affordability under different tariff structures
- minimising adverse customer impacts between years
- in this early phase of implementation and transition, allowing choice and control
- aligning drivers of customer usage with network investment and our operational cost drivers
- addressing distortionary pricing signals that lead to cross subsidies between different users and an overall increase in the cost of energy delivery.

As part of our customer consultation process, we also raised possible transitional approaches to the application of the new LRMC values to peak charging components in our optional tariffs, noting that immediate transition of peak charging components to our updated LRMC value has the following challenges:

- As discussed above, our LRMC calculations were originally based on expectations on growth, expenditure and rate of return as at the time of our October 2014 Regulatory Proposal. We have since updated our LRMC calculations to reflect outcomes of the AER's Distribution Determination in October 2015. These values may not be sustained in the future.
- Given the optional nature of these tariffs with a peak charging component based on LRMC, Ergon Energy needs to provide an incentive for customers on default tariffs to transition to an optional tariff. This means that we need to have regard to customers' likely willingness to move from a legacy tariff that will only gradually reflect LRMC to an optional tariff that immediately reflects the latest LRMC value. This has encouraged us to pursue a gradual approach to the application of the LRMC values developed in the Colebourn report to our optional tariffs.

6.5.1 Customer price impacts

We have analysed the impact of each annual change to DUOS rates on individual customers over the 2017 to 2020 period. As customer circumstances change, our analysis has been limited to the customer specific impact of any tariff reform such as tariff structure changes or parameter reweighting.

For our legacy tariffs, we have deliberately moved slowly to incorporate LRMC into tariff levels so as to limit adverse customer impacts, which – particularly in an environment of rising fixed charges – tend to be particularly acute for the smaller customers within each tariff class or sub-class.

In some circumstances we have analysed a sample of customers to determine likely impacts. We have applied constraints on price impacts for tariff classes so that there is not a substantial differential in revenue recoveries between each class. We have also set maximum limits on the potential individual customer impacts (which vary depending on the extent to which general movements in revenue are increasing or decreasing) to ensure that individual customers are not, where it can be avoided, impacted excessively by the reforms.

In developing these constraints we balanced:

- the need to phase in changes progressively to provide customers with notice to respond
- the cost of retaining the inefficiency associated with tariff structures that distort customer price signals
- the NER drivers to progressively move toward a suite of tariffs that maximise achievement of the network pricing objective.

Additionally we noted that:

- Individual customer impacts attributable to tariff reform will often impact a large number of customers marginally and small number of outliers significantly.
- Overly constraining the individual customer impact will limit restructuring scope with the bulk of customers and limit the pace of realising the benefits of more efficient tariffs.
- Setting constraints at levels which are too conservative also means that new customers continue to respond to and develop their network usage to legacy price distortions for longer, which may have more significant impacts for a greater proportion of customers than transitioning to cost reflective tariffs.

A slightly different approach was applied to 'opt in' tariffs. Our approach has been to ensure that our optional tariffs are relatively attractive to a large number of customers who have the choice to move, or to stay on less efficient default tariffs. Designing these tariff structures will create outliers on both sides:

- some customers may receive significantly reduced charges, indicating they have been paying more than the efficient price through legacy tariffs
- other customers may receive significantly higher charges, indicating they have been paying less than the efficient price through legacy tariffs.

We expect a slow transition to LRMC-based charges, even for those customers who are paying more than the efficient price now. Behavioural analysis also suggests that customers are unlikely to transition to something 'new' unless there are clear and tangible benefits. Applying constraints on customers who may be better off under more efficient tariffs would likely ensure no transition to LRMC-based tariffs. On this basis we have not applied further constraints on price impacts on optional tariffs.

6.5.2 Reflecting our network signal in regulated retail prices for regional Queensland

In our *Supporting Information - Revised TSS* we noted that, for residential and small to medium business customers who use less than 100 MWh of electricity a year, our IBT tariff structure and our rates for all tariff structures are not used as the basis for the QCA's regulated retail tariffs. These tariffs, which are accessed by the majority of customers in regional Queensland, are largely based on Energex's network charges for south east Queensland.

While we have maintained an approach to calculating tariffs consistent with NER requirements and how this may impact customers, 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 also dependent on the QCA's own review of prices and the underlying prices put forward by Energex.

6.6 Keeping it simple – easy to understand tariffs

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

- *the type and nature of those retail customers*
- *the information provided to, and the consultation undertaken with, those retail customers.*

The introduction of LRMC-based tariffs will mean that residential and small to medium business customers will see new and different tariff structures and components. The majority of these components have been known and understood by larger businesses for some time. Still, our stakeholder engagement has delivered a strong message of the need for the introduction of these tariffs to be accompanied by customer information, advice and education to allow customers to effectively respond to the new choices that are being presented to them.

We do not expect this to happen overnight. Our experience is that some customers have difficulty understanding their retail bill now, let alone some of the complicated arrangements that have created a disconnect between the charges we apply in pricing proposals and the final rates some customers see.

Historically, customer retail prices have been set by taking relatively simple two or three part tariffs and adding a retail margin to reflect the cost of energy purchase and retailer costs. Including other tariff components in the tariff structure provides an opportunity for retailers to 'bundle' several different tariff components to improve understanding for customers.

We intend to engage with the QCA on developing a regulated retail tariff for residential customers that is underpinned by our cost reflective network tariff, but is offered to the customer as a set monthly rate with a certain amount of demand and volume included. In other words, network access charges are not passed through to a customer with a margin. Instead, retailers offer customers a monthly charge with excess usage fees. These rates are prevalent in similar industries (such as telecommunications and gas) and are now well understood by customers.

We expect this transition will take time and in the short term we will continue to inform customers through normal channels such as information papers and webinars. We will also look at options for providing more real time information through the use of trials or pilots and shadow billing.

6.7 Compliance with the NER and other regulatory instruments

A tariff must comply with the NER and all applicable regulatory instruments.

Our tariffs have been developed to be compliant with the NER as described in this document, and other regulatory instruments applicable to regional Queensland tariff development. This includes compliance with the AER's *Final Decision: Ergon Energy determination 2015-16 to 2019-20* (the 'Distribution Determination'), in particular its control mechanism for SCS. We will demonstrate compliance with these and, where necessary, any other regulatory obligations and requirements in our annual Pricing Proposal.

7. Indicative prices

7.1 Indicative pricing schedule

Appendix A sets out actual and indicative prices for our SCS network tariffs for the 2015-20 regulatory control period.[27]

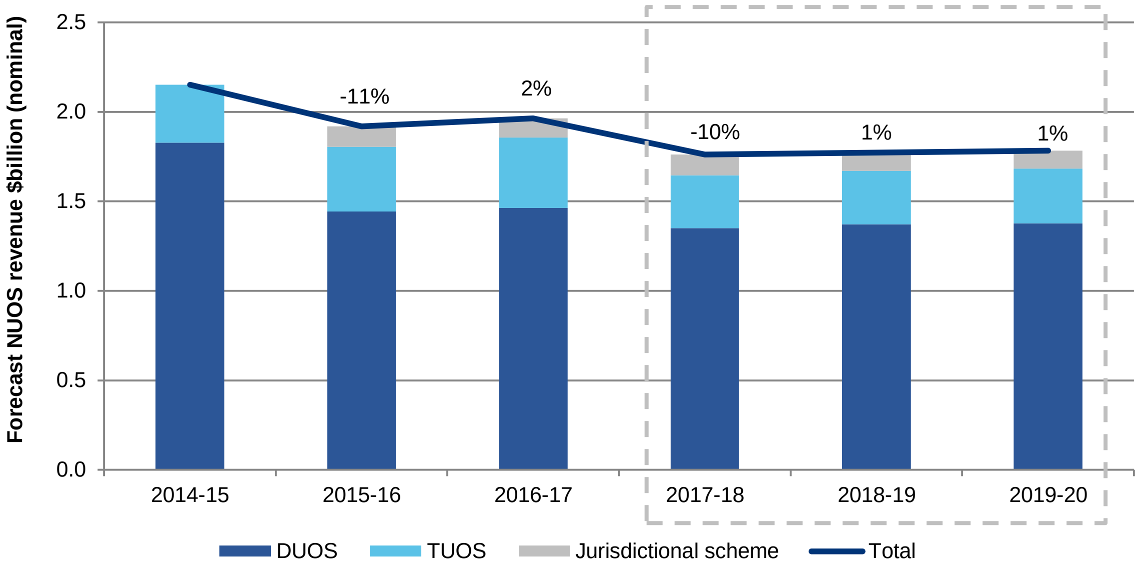
In order to provide indicative prices, Ergon Energy forecasts a number of inputs. This means the actual prices that will apply in any given year will differ from those contained in Appendix A.

Prices may change as a result of:

- adjustments approved by the AER in the relevant pricing year (such as under or over recovery of NUOS charges and changes in inflation)
- for major customers, changes to individual customers' circumstances (e.g. a change in connection assets, power factor, consumption, authorised demand or shared network asset utilisation)
- changes in NUOS charges not controlled by Ergon Energy (e.g. Powerlink's transmission charges or recovery of feed-in tariff payments made in respect of the Queensland Government's Solar Bonus Scheme)
- changes in underlying forecasts (e.g. demand and customer numbers) underpinning the estimates and incorporation of actual outcomes of forecast inputs.

7.1.1 Average price impacts for customers

We anticipate annual overall changes in the NUOS charges to remain relatively flat over the period, as shown in Figure 3.



27 We have provided indicative prices for each of our SAC and CAC network tariffs. However, due to confidentiality reasons, we have not published site-specific network tariffs for ICCs and EGs, or the customer-specific connection units applying to individual CACs. Doing so would breach clause 6.19.2 of the NER and any connection agreements between Ergon Energy and our customers.

Figure 3: Forecast annual changes in NUOS revenue recovery

The above figure demonstrates that the money Ergon Energy collects for the use of the network has fallen, and remains below what we recovered in 2014-15 for the remainder of this regulatory control period.

The increase in revenue recovery in 2016-17 is largely attributable to an increase in charges to Powerlink (TUOS) and an allowance for under-recoveries from 2014-15.

The overall revenue reductions are in line with our efficiency drive and a range of other factors. A falling revenue recovery profile provides an ideal environment to manage the implementation of our tariff reform agenda.

Like our indicative prices, our total NUOS revenue recovery is expected to change as more up-to-date information becomes available.

7.2 Approach to setting each tariff 2017-2020

The approach that Ergon Energy will take to establishing tariffs in each Pricing Proposal is described in Chapter 4.

8. Assigning and reassigning customers to network tariffs

Appendix D sets out Ergon Energy's procedures on assigning and reassigning customers to SCS tariff classes and network tariffs.

Part 3 – Alternative Control Services

9. Understanding user-specific charges

User-specific charges for ACS are levied on the customer or retailer requesting the service and are separate to the tariffs that apply for SCS.

Chapter 3 explains key pricing concepts used in this TSS (e.g. what a tariff class is). These concepts also apply for tariffs relating to ACS. However, as most of these tariffs relate to services specific to a customer, there is less need for Ergon Energy to group customers or develop detailed structures for revenue recovery.

For ACS, Ergon Energy uses two broad types of charges:

- fixed charge
  - $ per service
  - $ per call out
  - $ per day per meter
  - $ per day per light
  - $ per light
- quoted price, determined to reflect the actual requirements of the service
  - $ per service
  - $ per call out
  - $ per light.

10. Tariff structures

This chapter details our ACS tariff classes and their respective tariff structures, including the charging parameters, that are proposed to apply in 2017-18 to 2019-20.

10.1 Tariff classes

The AER has a primary role in determining how we categorise and calculate ACS charges. The AER's Distribution Determination (Attachments 13 and 16) provides the reasoning behind the AER's decisions on the prices it set for the various services it classified. Ergon Energy's tariff classes for ACS are therefore 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** – one-off distribution services that Ergon Energy undertakes at the request of an identifiable customer, retailer or appropriate third party which are in addition to our SCS and are levied as a separate charge. These services are priced on a 'fixed fee' basis as the costs of providing the service (and therefore price) can be assessed in advance of the service being requested by a customer or retailer.

  Examples of fee based services include Type 5 and 6 meter installation and provision (on or after 1 July 2015)[28] where the new or upgraded meter is required as a result of a customer request, 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 retailer's or customer's needs (e.g. design and construction of connection assets for major customers, real estate development connections and special meter reads).
- **Default Metering Services** – relate to:
  - Type 5 and 6 meter installation and provision (before 1 July 2015)
  - Type 5 and 6 meter installation and provision (on or after 1 July 2015) where the replacement meter is initiated by Ergon Energy as a distributor
  - Type 5 and 6 metering maintenance, reading and data services.

  Ergon Energy recovers our costs of providing Default Metering Services through capital and non-capital charges based on the number and type of meters we provide the customer.
- **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 operational life[29].

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

We have five tariff classes for ACS, as set out in Table 5. These tariff classes are the same as those applying in 2015-16 and 2016-17.

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[28] During business hours.
[29] Outside of our LED transition program.

Table 5: Ergon Energy's ACS tariff classes

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

10.2 Fee based services

In the 2017 to 2020 period, there are 26 fee based services.

In addition, where Ergon Energy attends a premises and is unable to complete the work due to customer or retailer fault (e.g. a dangerous dog or a locked gate), we will charge a call out fee to reflect the opportunity cost of the fleet and labour resources.

Each of these services and call out fees is set out in Appendix B.

Changes since 2015-16

Our product range has been developed in accordance with the AER's classification of services and is largely consistent with the services offered in 2015-16. There are two changes:

- Consistent with the Distribution Determination, there are eight new fee based services relating to the installation and provision of Type 5 and 6 meters on or after 1 July 2015 (during business hours).[30] [31] These services are differentiated by the type of meter (i.e. single phase, dual element, polyphase and current transformer) and the type of feeder the customer is connected to (i.e. either urban/short rural or long rural). These services replace the upfront capital charges that previously formed part of Default Metering Services. Call out fees for these services have also been developed.
- The four 'Prevented Access' charges have been removed. In the Distribution Determination, the AER decided that costs of wasted truck visits that are incurred in providing SCS should not be recovered through a separate ACS charge. Rather, these costs should be recovered as a SCS (i.e. via network tariffs).

10.2.1 Charging parameters

A fixed charge ($ per service) applies to our fee based services. The fixed charge reflects the estimated cost of providing each service and varies depending on the type of fee based service being requested.

The call out fee is a fixed charge ($ per call out), which varies by the type of fee based service that

[30] The Distribution Determination refers to these charges as 'upfront capital charges'.

[31] Due to system limitations, in 2015-16, Ergon Energy decided to implement a transition solution for upfront metering charges associated with the installation of new meters. New installations will generally incur an upfront metering charge, plus a daily capital charge for a period of two years from the date of installation. To achieve a cost neutral outcome for the customer, the relevant AER-approved upfront metering charge will be discounted by the Net Present Value of two years' worth of the relevant capital charge(s).

the original call out was for.

10.3 Quoted services

There are 59 quoted services available for selection during the 2017 to 2020 period. Each of these services is set out in Appendix B.

The costs of wasted attendance for quoted services are recovered via a call out fee.

Changes since 2015-16

Our product range has been determined based on the AER's classification of services and is largely consistent with the services offered in 2015-16. We have made the following changes:

- removed our 'Install additional metering' service in line with our revised Regulatory Proposal
- introduced a new service, 'Installation and provision of Type 5 and 6 meters after hours', to align with the Distribution Determination
- expanded the 'Detailed enquiry response fee' service to include any embedded generation connection applicant that submits an enquiry under the connection process set out in Chapter 5 of the NER. This is consistent with the *Connecting embedded generators under Chapter 5A* rule change, which allows non-registered embedded generators to elect to proceed under Chapter 5 of the NER and seek a detailed response
- amended the 'Carrying out planning studies and analysis relating to connection applications' service to include real estate developers
- removed reference to small or major customer connections from the 'Provision of site-specific connection information and advice' service, to clarify that this service includes real estate development connections
- expanded the 'Customer requested appointments' service to explicitly include retailers and amended the service description
- clarified that the 'Special meter read' service does not include final meter reads. The costs of final meter reads are included in the operating expenditure building block of the annual metering charges
- amended the 'Change tariff' service description to include reprogramming for adding or removing tariffs.
- The 'Provision of services for approved unmetered supplies' service also became available from 1 July 2016.

10.3.1 Charging parameters

A quoted price ($ per service) applies to our quoted services. The quoted price is based on several types and quantities of inputs that vary depending on the actual requirements of the service requested. Therefore, there will be differences in charges for each quoted service reflecting the nature of the resources required to meet the requestor's needs.

The call out fee is a quoted price ($ per call out), which reflects the actual costs incurred in attending the premises.

10.4 Default Metering Services

Ergon Energy has developed six metering service charges, which are distinguished by:

- the type of metering service
  - primary
  - controlled load
  - embedded generation[32]
- the type of cost recovery
  - capital[33]
  - non-capital.[34]

The costs of wasted attendance associated with final meter reads[35] are recovered via a call out fee.

Each of these tariffs and call out fees is set out in Appendix B.

Changes since 2015-16

Our product range has been developed in accordance with the AER's classification of services and is largely consistent with the services offered in 2015-16. We have made the following changes:

- expanded the 'solar' capital and non-capital metering charges to include other forms of embedded generation (and renamed the service 'embedded generation'). Ergon Energy is starting to see an increase in alternative technologies, such as battery only micro-embedded generating units, which require the installation of a new meter the same as solar photovoltaic (PV) systems.
- Developed call out fees for final meter reads. We have established two call out fees, which are differentiated by the type of the feeder the customer is connected to (i.e. urban/short rural or long rural). This is consistent with Attachment 16 of the Distribution Determination.

10.4.1 Charging parameters

The following charging parameters apply to Default Metering Services:

- Metering service charges – a fixed charge ($ per day per meter)
- Call out fee – a fixed charge ($ per call out).

10.5 Public Lighting Services

Ergon Energy has developed four tariffs for our Public Lighting Services, which are distinguished by:

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[32] Metering service was previously known as 'solar'. The solar capital and non-capital metering charges were expanded in 2016-17 to include other forms of embedded generation.
[33] Metering asset base recovery and tax.
[34] Operating expenditure.
[36] Refer to Ergon Energy's forecast expenditure summary (public lighting services) submitted as part of our revised Regulatory Proposal for details.

- the ownership status
  - Ergon Energy Owned and Operated (EO&O)
  - Gifted and Ergon Energy Operated (G&EO)
- the size of the lamp
  - Major – includes the following lantern types:
    - Metal Halide – above 125 W
    - Mercury Vapour – above 125 W
    - High Pressure Sodium – above 100 W
  - 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

The AER allows Ergon Energy to charge a one-off exit fee when a customer requests the replacement of an existing public light for a Light Emitting Diode (LED) light.[36] We have developed four public lighting exit fees. These fees are distinguished by the ownership status and the size of the lamp. Exit fees are not payable by customers where the proposed LED transition program is being implemented.

Each of these tariffs and exit fees is set out in Appendix B and is consistent with those tariffs offered in 2015-16.

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

10.5.1 Charging parameters

The following charging parameters apply:

- Public Lighting Services – a fixed charge ($ per day per light)
- Exit fee – a fixed charge ($ per light)
- Non-standard public lights – a quoted price ($ per light).

[36] Refer to Ergon Energy's forecast expenditure summary (public lighting services) submitted as part of our revised Regulatory Proposal for details.

11. Establishing tariffs for Alternative Control Services

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

The approach to setting tariffs varies for each type of ACS. This chapter explains in detail our tariff-setting processes.

11.1 Tariff-setting process for fee based and quoted services

11.1.1 Fee based services

In 2015-16, Ergon Energy developed prices for our fee based services using the cost build-up formula for quoted services (see Section 11.1.2). These prices incorporated our estimate of the cost of labour (inclusive of fleet) and materials (as appropriate) used in the provision of each service, plus a capital allowance.

We will use the same cost build-up formula to calculate prices in subsequent years of the regulatory control period 2015-20. However, we will limit the annual price increases for fee based services to the lower of the calculated amount and the cap imposed by the AER's price cap formula.

Calculating the cost build-up price

Labour

Ergon Energy will apply the same underlying assumptions used to set prices for 2015-16 for each fee based service. These assumptions relate to:

- the estimated travel time and time required to undertake the service (the 'total time on the job')
- the type and number of staff required to perform the service
- the type of fleet required
- the estimated time the fleet is required, including idle time while the work is carried out.

The labour rate (inclusive of labour on costs and overheads) for each employee position will be multiplied by their total time on the job. These unit costs will then be totalled to derive an overall labour cost for the service.

For services where travel is required, a fleet on cost will also be applied. The fleet rate (inclusive of overheads) for the vehicle[37] will be multiplied by the total time the vehicle is required.

Materials

Materials are only used in the delivery of the 'Installation and provision of Type 5 and 6 meters' services. The materials costs are determined by multiplying the relevant meter unit cost by the materials (internal stores) on cost rate and the overhead rate.

[37] Ergon Energy has assumed that a 2WD Commercial vehicle is used in the delivery of fee based services where travel is required. Further, where two employees are involved in the delivery of the service, Ergon Energy has assumed that both employees travel to the customer's premises in the same vehicle.

Capital allowance

The capital allowance will be calculated by multiplying the total labour costs (inclusive of labour on costs and overheads) by the Capital Allowance rate.

Annual changes to cost inputs

We will annually update a number of the cost inputs. Specifically, we will:

- update the nominal labour, fleet and material escalation rates for the actual December to December quarter Consumer Price Index (CPI) published by the Australian Bureau of Statistics (ABS) for the relevant pricing year. This will impact the base labour rates, fleet rates and meter unit costs used in the calculation of each price
- update the labour and materials on cost rates for the relevant pricing year, as appropriate
- determine the overhead rates for the relevant pricing year in accordance with the AER-approved Cost Allocation Method (CAM).

These inputs will be submitted to the AER for approval in the relevant annual Pricing Proposal.

Calculating the capped price

Consistent with Figure 16.2 in Attachment 16 of the Distribution Determination, Ergon Energy will apply the following formula to determine the capped price for each fee based service:

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

Where:

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

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

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from the December quarter in year t–2 to the December quarter in year t–1, 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 2016-17 year, t–2 is the December quarter 2014 and t–1 is the December quarter 2015 and in the 2017-18 year, t–2 is the December quarter 2015 and t–1 is the December quarter 2016 and so on.

X_t^i is:

- for service i in year t that are an upfront capital charge, the X factor as set out in Table 16.3 [of the Distribution Determination]
- for service i in year t that are not an upfront capital charge, the X factor as set out in Table 16.4 [of the Distribution Determination].

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

Determining which price to apply

For each fee based service, Ergon Energy will compare the price calculated under the cost build-up approach and the price determined using the AER's price cap formula. The price we submit in our annual Pricing Proposal for AER-approval will be the lower amount.

An illustrative example of how we will determine which price to apply is provided in Figure 4.

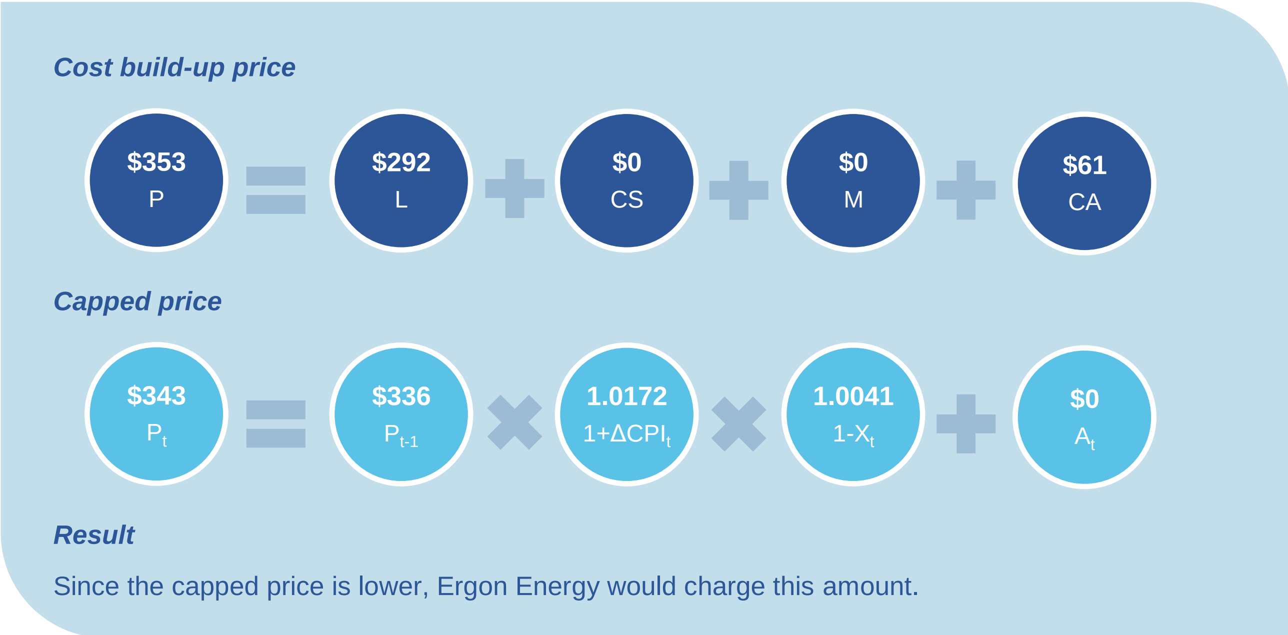

Figure 4: Illustrative example – which price will apply?

Call out fees

Ergon Energy will also apply the approach set out above to calculate the applicable call out fee associated with each fee based service.

Under the cost build-up approach, the call out fee for each fee based service will be calculated by:

- multiplying the total travel time labour costs for the particular service by the Capital Allowance rate
- adding the fleet on cost, which is the product of the hourly on cost rate (inclusive of overheads) and the total hours the vehicle was required for the job (travel time only).

To determine the capped call out fee, we will apply the price cap formula set out above. However:

- p_t^i will be the cap on the call out fee associated with service i in year t
- p_{t-1}^i will be the cap on the call out fee associated with service i in year t–1.

We will apply the X factors provided in Table 16.4 of the Distribution Determination to calculate the call out fees for all fee based services.

We will then submit the lower of the two amounts in our annual Pricing Proposal for AER-approval.

11.1.2 Quoted services

In accordance with Figure 16.3 in Attachment 16 of the Distribution Determination, Ergon Energy will apply the following formula when calculating prices to be levied for our quoted services:

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

Where:

Labour consists of all labour costs directly incurred in the provision of the service which may include labour on costs, fleet on costs and overheads. From 2016-17, base labour is escalated annually by (1 + ΔCPI_t)(1 - X_t^i), where:

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 2016-17 year, t–2 is the December quarter 2014 and t–1 is the December quarter 2015 and in the 2017-18 year, t–2 is the December quarter 2015 and t–1 is the December quarter 2016 and so on.

X_t^i is the X factor for service i in year t, as set out in Table 16.4 [of the Distribution Determination].

Contractor Services consists of all costs associated with the use of external labour including overheads and any direct costs incurred. The contractor services charge applies the rates under existing contractual arrangements. Direct costs incurred are passed on to the customer.

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

Capital Allowance represents a return on and return of capital for non-system assets.[38]

Annual changes to cost inputs

The quoted services formula establishes a price cap on base labour rates only. To comply with this price cap, Ergon Energy will annually update the AER-determined nominal labour escalation rates for the relevant pricing year for the actual December to December quarter CPI published by the ABS.

[38] Excludes vehicle depreciation, which is included in the fleet on cost.

In addition, we will annually update the following cost inputs:

- the nominal fleet escalation rates for the relevant pricing year for the actual December to December quarter CPI published by the ABS
- the labour and materials on cost rates, as appropriate
- the overhead rates, in accordance with the AER-approved CAM.

For the purposes of developing indicative prices for our annual Pricing Proposal, we will also annually update the nominal materials and contractor services escalation rates for the relevant pricing year for the actual December to December quarter CPI published by the ABS. This will impact the base Contractor Services and Materials costs used in our illustrative examples only. This is because Ergon Energy will charge the actual costs incurred for Contractor Services and Materials (plus on costs and overheads, as relevant), depending on the requirements of the job requested.

Changes to cost inputs will be submitted to the AER for approval in the relevant annual Pricing Proposal.

Call out fees

For quoted services where Ergon Energy is unable to perform the service after the truck has left the depot (due to no fault of our own), we will charge for the actual costs incurred in accordance with the quoted services formula detailed above.

11.2 Tariff-setting process for Default Metering Services

For Default Metering Services, a limited building block approach is used to determine the allowable revenue over the regulatory control period, which is then converted into capital and non-capital annual metering service charges that are subject to a price cap.

Our revenue requirement is comprised of the following building blocks:

- the return on capital, return of capital (regulatory depreciation) and tax allowance for Type 5 and 6 meters installed up to 30 June 2015 and Type 5 and 6 meters expected to be installed on or after 1 July 2015 (where the replacement is initiated by Ergon Energy)
- the operating expenditure for Type 5 and 6 meters installed up to 30 June 2015 and for all new and replacement meters expected to be installed after 30 June 2015.

A price cap will also apply to the call out fees for final meter reads.

11.3 Calculating Default Metering Services tariffs

Annual metering service charges

Our six annual metering service charges will be calculated using the following price cap formula:

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

Where:

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

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

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from the December quarter in year t–2 to the December quarter in year t–1, 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 2016-17 year, t–2 is the December quarter 2014 and t–1 is the December quarter 2015 and in the 2017-18 year, t–2 is the December quarter 2015 and t–1 is the December quarter 2016 and so on.

X_t^i is:

- for service i (annual metering charge – non-capital component) in year t, the X factor as set out in Table 16.9 [of the Distribution Determination]
- for service i (annual metering charge – capital component) in year t, the X factor as set out in Table 16.10 [of the Distribution Determination].

A_t^i is an adjustment factor for residual charges when customers choose to replace assets before the end of their economic life. For the annual metering charge, the value of A is zero.

For billing purposes, Ergon Energy will convert the annual metering service charges into daily charges.

Call out fees

The call out fees for final meter reads will be calculated using the price cap formula set out above. However:

- p_t^i will be the cap on the call out fee associated with service i in year t
- p_{t-1}^i will be the cap on the call out fee associated with service i in year t–1.

We will apply the X factors detailed in Table 16.4 of the Distribution Determination for fee based services.

11.4 Tariff-setting process for Public Lighting Services

For Public Lighting Services, a limited building block approach is used to determine the efficient costs (and price). This involves the AER approving allowances for the ‘building block’ elements (i.e. return on assets, depreciation, operating expenditure and tax) in order to determine Ergon Energy’s allowable revenue over the regulatory control period. The allowable revenue is then translated into public lighting charges that are subject to a price cap.

A price cap will also apply to our public lighting exit fees.

11.5 Calculating Public Lighting Services tariffs

Public lighting charges

Ergon Energy will apply the following price cap formula when calculating each of our four public lighting charges:

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

Where:

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

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

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from the December quarter in year t–2 to the December quarter in year t–1, 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 2016-17 year, t–2 is the December quarter 2014 and t–1 is the December quarter 2015 and in the 2017-18 year, t–2 is the December quarter 2015 and t–1 is the December quarter 2016 and so on.

X_t^i is the X factor for service i in year t, as set out in Table 16.2 [of the Distribution Determination].

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

Exit fees

Our four public lighting exit fees will be calculated by escalating the previous year's fee by inflation (refer to ΔCPI_t in the above price cap formula).

Contribution towards non-standard public lights

If Ergon Energy is requested by a customer to construct non-standard public lights, the amount payable by the customer will be the incremental cost difference between a standard and non-standard public light calculated in accordance with AER requirements. Ergon Energy will calculate the incremental cost as the shortfall between:

- the present value of expected revenue to be paid by the customer for Public Lighting Services over the life of a standard public lighting asset. This revenue is calculated using the relevant public lighting charge, and

the estimated cost of providing the non-standard public lighting asset. These costs are calculated in accordance with the formula for quoted services set out in Section 11.1.2 .

12. Meeting the pricing principles

Compared to SCS, Ergon Energy plays a lesser role in determining ACS prices. ACS tariffs are largely set by the AER through caps on the prices of individual services, with the majority of inputs used to develop these prices:

- being set by the AER at the time of the Distribution Determination, or
- approved by the AER during the annual pricing process.

No further allocation or structuring of the tariff is undertaken by Ergon Energy beyond the application of the control mechanism between years which is demonstrated in our Pricing Proposal.

This chapter addresses how our ACS tariffs and tariff structures meet the pricing principles, taking into account the form of control determined by the AER.

12.1 Network pricing objective

The network pricing objective requires our ACS tariffs to reflect our efficient costs of providing services to customers.

As noted above, the AER has decided to apply caps on the prices of individual ACS. This form of control generally involves the AER estimating the efficient cost of providing each service and setting the price at that cost in the first regulatory year (i.e. 2015-16). In determining the efficient cost of providing each service, the AER relies on a range of assessment techniques, including benchmarking. For subsequent years, the previous year's prices are adjusted in accordance with the relevant price cap formula set out in the Distribution Determination.

Importantly, when setting ACS prices, the AER must promote the efficient operation and use of services for the long term interests of consumers with respect to price, quality, safety, reliability and security of supply.

For quoted services, the AER establishes an initial price cap on base labour rates. These base labour rates are then escalated annually in accordance with the quoted services formula outlined in the Distribution Determination. Other cost inputs are approved by the AER at the time of the Distribution Determination or through the annual pricing process, or are charged at cost (i.e. we pass on costs we directly incur for materials and contractor services).

Ergon Energy calculates our ACS tariffs in accordance with the relevant price cap formula set by the AER. As such, our ACS tariffs reflect our efficient costs (as determined by the AER) of providing services to our customers.

12.2 Avoidable and stand-alone costs

Our approach to determining avoidable and stand-alone costs for our fee based services, quoted services, Public Lighting Services and Default Metering Services is set out below. Consistent with this approach, we have not undertaken quantitative analysis of our stand-alone and avoidable costs for ACS.

12.2.1 Fee based and quoted services

The very nature of user-specific services means that there is a more direct link between the service the customer requests and the costs of providing the service. Ergon Energy provides our ACS using a mix of shared and dedicated physical assets and labour. We price each of these services on a full cost recovery basis using the formulae approved by the AER.

We note the AER must establish controls over the revenue recovered or prices paid for these services having regard to the NER and the National Electricity Law. We also note in the Distribution Determination that the AER has determined charges based on what it believes will promote the efficient provision of electricity services and allow a return commensurate with the regulatory and commercial risks involved for the provision of those services. Ergon Energy prices in accordance with the Distribution Determination and relies on the application of the AER's decision to achieve revenue recovery between the upper and lower bounds.

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

The avoidable cost of ACS is the cost incurred in the delivery of the services to a tariff class if no services were provided to any other tariff class. The only avoided costs relating to ACS are labour costs charged on an hourly basis, materials consumed during the course of providing the service and contractor services costs incurred. Given that the formula used to derive prices for fee based and quoted services includes a component of shared costs, the total revenue for tariff classes will exceed the avoidable portion.

12.2.2 Default Metering Services

Since Ergon Energy has proposed one Default Metering Services tariff class, the revenue expected to be recovered from this tariff class will be equal to the allocation of the Annual Revenue Requirement (ARR) for Default Metering Services plus any additional revenue recovered from call out fees associated with final meter reads. Ergon Energy intends to recover revenue consistent with the schedule of prices per meter determined by the AER in 2015-16, adjusted in subsequent years by the price cap formula. These prices were based on the AER's own determination of efficient costs on a per unit basis, using a combination of high level benchmarking and assessing the assumptions used in the build-up of costs.

By applying the AER's determination of efficient prices, we understand that the calculated prices will result in the recovery of efficient costs and expected revenue between the upper and lower bounds.

12.2.3 Public Lighting Services

Since Ergon Energy has proposed one Public Lighting Services tariff class, the revenue expected to be recovered from this tariff class will be equal to the allocation of the ARR for Public Lighting Services plus any additional revenue recovered through the exit fees. Ergon Energy intends to recover revenue consistent with the schedule of prices per light determined by the AER in 2015-16, adjusted in subsequent years by the price cap formula. These prices were based on the AER's own determination of efficient costs on a per unit basis, using a combination of high level benchmarking and assessing the assumptions used in the build-up of costs.

Again, Ergon Energy relies on the application of the AER-determined efficient prices to result in the recovery of efficient costs and expected revenue between the upper and lower bounds.

12.3 Long run marginal cost

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 ACS. The AER therefore determines the LRMC of each tariff when it establishes the initial prices and sets the inputs, such as the X factors, to be used in the price cap formulae.

For fee based and quoted services, the user-pays charges recover the full cost of providing the service. Most of these costs are incremental and specific to the customer requesting the service.

For Default Metering Services, our daily metering service charges are differentiated by the type of meter (e.g. single phase) and the type of metering service requested (i.e. primary, controlled load and embedded generation metering services). The capital and non-capital charges are calculated according to the weighted forecast average of their respective costs in the ARR.

For Public Lighting Services, our daily public lighting charges are differentiated by whether:

- the customer gifted the public light to Ergon Energy, in which case the charge recovers the costs to maintain/operate and replace the light if it fails in service before the end of its useful life
- Ergon Energy constructed the public light, in which case the charge recovers the costs to acquire, maintain/operate and replace the light if it fails in service.

Distinguishing by the type of light (Major versus Minor) also ensures the charge reflects the appropriate capital costs.

12.4 Revenue recovery

The AER, through its price cap control mechanism, sets the basis on which we are allowed to recover the efficient costs of providing each service. The total amount of revenue recovered depends on the volume of services provided in the relevant year multiplied by the rates (or the schedule of rates, as is the case for quoted services) determined by the AER.

12.5 Impact on retail customers

The price cap control mechanism limits customer impacts by constraining annual price increases to a certain level. We would 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.

Customers are also 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).

12.6 Keeping it simple – easy to understand charges

Our ACS are accessed by all types of customers – from residential customers to large mining operators and government entities. We therefore structure each of our ACS tariffs with a view to being as simple and easy to understand as possible, while also supporting cost reflectivity.

Each ACS tariff comprises one charging parameter only. For most ACS tariffs, this is a fixed charge – the simplest and easiest to understand charging type. We publish these fixed charges in our annual *Price List for Alternative Control Services.*

For quoted services, we develop a user-specific quote based on the requestor's needs. This quote includes a breakdown of the costs we expect to incur in delivering the requested service. We also provide information in this TSS on how our quoted prices are determined, so that stakeholders can understand how their charge has been derived.

Our ACS tariff structures have not changed significantly from the structures that were in place in 2015-16 (which were subject to consultation through the regulatory determination process). Ongoing stability of the structures and customer familiarity with these structures assists customer understanding of the charges.

12.7 Compliance with the NER and other regulatory instruments

Our ACS tariffs have been developed to be compliant with the NER, as described in this document, and other applicable regulatory instruments.

13. Indicative prices

13.1 Indicative pricing schedule

Appendix B sets out actual and indicative prices for our ACS for the 2016-17 to 2019-20 period.

It is important to note that these prices are based on current information. Prices may change as a result of:

- the difference between forecast and actual inflation
- changes to underlying real costs (e.g. overheads, on costs, and direct materials and contractor services costs).

13.2 Annual updates

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

Our approach to establishing annual ACS tariffs under the price cap control mechanism is explained in detail in Chapter 11

14. Assigning and reassigning customers to tariffs

Appendix E sets out Ergon Energy's procedures on assigning and reassigning customers to ACS tariff classes and tariffs.

Appendix A Indicative pricing schedule for Standard Control Services

This appendix sets out indicative prices for our Network Use of System (NUOS) charges for the 2017-18 to 2019-20 period. Actual prices for 2015-16 and 2016-17 have also been set out in this appendix for completeness.

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.

Ergon Energy notes that the NER only require us to provide indicative prices for our Direct Control Services (i.e. SCS (DUOS) and Alternative Control Services (ACS)). However, to assist customers and retailers understand the full impact of our charges, we have provided indicative prices for TUOS and jurisdictional scheme charges too.

It is important to note that the 2017-18 to 2019-20 indicative prices detailed in this appendix are based on current expectations regarding annual pricing inputs. In particular:

- 2017-20 annual indicative rates are based on total revenue recovery amounts which will vary based on outcomes that will occur after submission of the TSS. Actual annual pricing will be impacted by these outcomes.
- The AER will release a new revenue determination for Powerlink during the TSS period. This will impact the amount of TUOS revenue we need to recover from customers.
- Jurisdictional scheme amounts relating to the Queensland Government's Solar Bonus Scheme are based on our forecasts of feed-in tariff (FiT) payments we expect to make for the relevant year. These FiT forecasts are based on the number of connected inverter energy systems expected to be eligible for the Solar Bonus Scheme in the relevant year, the mean size of the installed PV solar inverters and historical monthly export in kWh per unit of installed capacity. These factors are subject to change.
- Jurisdictional scheme amounts relating to the energy industry levy are estimated payments based on current information provided by the Queensland Government. Actual payments are subject to change

In this appendix each building block of NUOS is presented separately, with actual 2015-16 and 2016-17 rates and indicative 2017-20 estimates. For each tariff the relevant DUOS, TUOS and jurisdictional scheme charges are combined to determine the indicative NUOS.

In calculating network charges, the TUOS volume rates need to be adjusted by the customer's applicable Distribution Loss Factor (DLF). The standard 2016-17 DLFs are provided in this appendix. It is important to note that DLFs are recalculated and submitted to the AER for approval each year. Accordingly, 2016-17 DLFs are only indicative of future year outcomes. In addition, a specific loss factor may be applied where there is a unique network supply configuration.

1 Indicative DUOS prices

Table 6: SAC Small indicative DUOS prices

Tariff	Charging parameter	Units	2015-16	2016-17	2017-18	2018-19	2019-20
SAC Small default tariffs							
IBT Residential							
IBT Residential East (ERIB)	Fixed	$/day	1.250	1.250	1.250	1.250	1.250
	Volume Block 1	$/kWh	0.00000	0.02108	0.02161	0.02215	0.02270
	Volume Block 2	$/kWh	0.08821	0.08486	0.07257	0.07378	0.07318
	Volume Block 3	$/kWh	0.11817	0.12244	0.10471	0.10645	0.10559
IBT Residential West (WRIB)	Fixed	$/day	2.000	2.000	2.000	2.000	2.000
	Volume Block 1	$/kWh	0.06000	0.07000	0.07175	0.07354	0.07538
	Volume Block 2	$/kWh	0.34956	0.34526	0.29526	0.30018	0.29776
	Volume Block 3	$/kWh	0.39956	0.39653	0.33911	0.34476	0.34199
IBT Residential Mount Isa (MRIB)	Fixed	$/day	1.250	1.250	1.250	1.250	1.250
	Volume Block 1	$/kWh	0.00000	0.02114	0.02167	0.02222	0.02277
	Volume Block 2	$/kWh	0.04776	0.05104	0.04365	0.04438	0.04402
	Volume Block 3	$/kWh	0.05776	0.06188	0.05292	0.05380	0.05336
IBT Business							
IBT Business East (EBIB)	Fixed	$/day	1.250	1.250	1.250	1.250	1.250
	Volume Block 1	$/kWh	0.00000	0.02520	0.02583	0.02647	0.02713
	Volume Block 2	$/kWh	0.10850	0.10794	0.09231	0.09385	0.09310
	Volume Block 3	$/kWh	0.13852	0.14418	0.12330	0.12536	0.12435
IBT Business West (WBIB)	Fixed	$/day	2.000	2.000	2.000	2.000	2.000
	Volume Block 1	$/kWh	0.06000	0.07000	0.07175	0.07354	0.07538
	Volume Block 2	$/kWh	0.36024	0.35744	0.30567	0.31077	0.30827
	Volume Block 3	$/kWh	0.41024	0.40887	0.34966	0.35549	0.35263
IBT Business Mount Isa (MBIB)	Fixed	$/day	1.250	1.250	1.250	1.250	1.250
	Volume Block 1	$/kWh	0.00000	0.02514	0.02577	0.02641	0.02707
	Volume Block 2	$/kWh	0.06272	0.06850	0.05858	0.05956	0.05908
	Volume Block 3	$/kWh	0.08272	0.08962	0.07664	0.07792	0.07729

Appendix A: Indicative pricing schedule for Standard Control Services

Tariff	Charging parameter	Units	2015-16	2016-17	2017-18	2018-19	2019-20
SAC Small optional tariffs							
Seasonal TOU Energy Residential							
Seasonal TOU Energy Residential East (ERTOU)	Fixed	$/day	1.250	1.250	1.250	1.250	1.250
	Volume Peak	$/kWh	0.31808	0.35715	0.39287	0.43215	0.47537
	Volume Shoulder	$/kWh	0.31808	n/a	n/a	n/a	n/a
	Volume Off-Peak	$/kWh	0.05058	0.04898	0.04189	0.04258	0.04224
Seasonal TOU Energy Residential West (WRTOU)	Fixed	$/day	2.000	2.000	2.000	2.000	2.000
	Volume Peak	$/kWh	0.99402	1.09348	1.20283	1.32311	1.45543
	Volume Shoulder	$/kWh	0.99402	n/a	n/a	n/a	n/a
	Volume Off-Peak	$/kWh	0.25278	0.24440	0.20900	0.21249	0.21078
Seasonal TOU Energy Residential Mount Isa (MRTOU)	Fixed	$/day	1.250	1.250	1.250	1.250	1.250
	Volume Peak	$/kWh	0.31808	0.35719	0.39290	0.43220	0.47542
	Volume Shoulder	$/kWh	0.31808	n/a	n/a	n/a	n/a
	Volume Off-Peak	$/kWh	0.01167	0.01356	0.01160	0.01179	0.01170
Seasonal TOU Energy Business							
Seasonal TOU Energy Business East (EBTOU)	Fixed	$/day	1.250	1.250	1.250	1.250	1.250
	Volume Peak	$/kWh	0.28945	0.32501	0.35751	0.39326	0.43259
	Volume Shoulder	$/kWh	0.28945	n/a	n/a	n/a	n/a
	Volume Off-Peak	$/kWh	0.09420	0.09155	0.07829	0.07960	0.07896
Seasonal TOU Energy Business West (WBTOU)	Fixed	$/day	2.000	2.000	2.000	2.000	2.000
	Volume Peak	$/kWh	0.90456	0.99507	1.09458	1.20403	1.32444
	Volume Shoulder	$/kWh	0.90456	n/a	n/a	n/a	n/a
	Volume Off-Peak	$/kWh	0.29686	0.28258	0.24166	0.24569	0.24371
Seasonal TOU Energy Business Mount Isa (MBTOU) Tariff	Fixed	$/day	1.250	1.250	1.250	1.250	1.250
	Volume Peak	$/kWh	0.28945	0.32504	0.35754	0.39330	0.43263
	Volume Shoulder	$/kWh	0.28945	0.32501	0.35751	0.39326	0.43259
	Volume Off-Peak	$/kWh	0.04388	0.04731	0.04046	0.04113	0.04080
Seasonal TOU Demand Residential							
Seasonal TOU Demand Residential East (ERTOUD)	Fixed	$/day	0.000	0.000	0.000	0.000	0.000
	Actual Demand Peak	$/kW/month	64.821	72.782	80.061	88.067	96.873
	Actual Demand Off-Peak	$/kW/month	12.000	13.261	11.340	11.529	11.437
	Volume Peak	$/kWh	0.03131	0.02000	0.01710	0.01738	0.01724
	Volume Off-Peak	$/kWh	0.03131	0.02000	0.01710	0.01738	0.01724

Appendix A: Indicative pricing schedule for Standard Control Services

Tariff	Charging parameter	Units	2015-16	2016-17	2017-18	2018-19	2019-20
Seasonal TOU Demand Residential West (WRTOUD)	Fixed	$/day	0.000	0.000	0.000	0.000	0.000
	Actual Demand Peak	$/kW/month	162.053	182.311	200.542	220.596	242.656
	Actual Demand Off-Peak	$/kW/month	20.000	20.000	17.103	17.388	17.248
	Volume Peak	$/kWh	0.18971	0.14161	0.12110	0.12312	0.12213
	Volume Off-Peak	$/kWh	0.18971	0.14161	0.12110	0.12312	0.12213
Seasonal TOU Demand Residential Mount Isa (MRTOUD)	Fixed	$/day	0.000	0.000	0.000	0.000	0.000
	Actual Demand Peak	$/kW/month	64.821	72.789	80.068	88.075	96.883
	Actual Demand Off-Peak	$/kW/month	10.356	10.388	8.884	9.032	8.959
	Volume Peak	$/kWh	0.00000	0.01000	0.00855	0.00869	0.00862
	Volume Off-Peak	$/kWh	0.00000	0.01000	0.00855	0.00869	0.00862
Seasonal TOU Demand Business							
Seasonal TOU Demand Business East (EBTOUD)	Fixed	$/day	0.000	0.000	0.000	0.000	0.000
	Actual Demand Peak	$/kW/month	80.554	90.448	99.493	109.442	120.387
	Actual Demand Off-Peak	$/kW/month	12.000	14.862	12.709	12.921	12.817
	Volume Peak	$/kWh	0.02835	0.02800	0.02394	0.02434	0.02414
	Volume Off-Peak	$/kWh	0.02835	0.02800	0.02394	0.02434	0.02414
Seasonal TOU Demand Business West (WBTOUD)	Fixed	$/day	0.000	0.000	0.000	0.000	0.000
	Actual Demand Peak	$/kW/month	201.386	226.561	249.218	274.139	301.553
	Actual Demand Off-Peak	$/kW/month	24.053	20.000	17.103	17.388	17.248
	Volume Peak	$/kWh	0.20000	0.16959	0.14503	0.14744	0.14626
	Volume Off-Peak	$/kWh	0.20000	0.16959	0.14503	0.14744	0.14626
Seasonal TOU Demand Business Mount Isa (MBTOUD)	Fixed	$/day	0.000	0.000	0.000	0.000	0.000
	Actual Demand Peak	$/kW/month	80.554	90.457	99.503	109.453	120.398
	Actual Demand Off-Peak	$/kW/month	7.056	5.000	4.275	4.347	4.312
	Volume Peak	$/kWh	0.00000	0.01327	0.01135	0.01154	0.01145
	Volume Off-Peak	$/kWh	0.00000	0.01327	0.01135	0.01154	0.01145
SAC Small secondary tariffs							
Controlled load							
Volume Night Controlled East (EVN)	Fixed	$/day	0.110	0.110	0.094	0.095	0.094
	Volume	$/kWh	0.03500	0.04000	0.04100	0.04202	0.04307
Volume Night Controlled West (WVN)	Fixed	$/day	0.138	0.138	0.118	0.119	0.119
	Volume	$/kWh	0.07500	0.08000	0.08200	0.08405	0.08615

Appendix A: Indicative pricing schedule for Standard Control Services

Tariff	Charging parameter	Units	2015-16	2016-17	2017-18	2018-19	2019-20
Volume Night Controlled Mount Isa (MVN)	Fixed	$/day	0.148	0.148	0.126	0.128	0.127
	Volume	$/kWh	0.03500	0.04000	0.04100	0.04202	0.04307
Volume Controlled East (EVC)	Fixed	$/day	0.110	0.110	0.094	0.095	0.094
	Volume	$/kWh	0.04000	0.04500	0.04612	0.04727	0.04846
Volume Controlled West (WVC)	Fixed	$/day	0.138	0.138	0.118	0.119	0.119
	Volume	$/kWh	0.10000	0.10500	0.10762	0.11031	0.11307
Volume Controlled Mount Isa (MVC)	Fixed	$/day	0.148	0.148	0.126	0.128	0.127
	Volume	$/kWh	0.04000	0.04500	0.04612	0.04727	0.04846
Demand Controlled East (EDC)	Fixed	$/day	n/a	n/a	0.094	0.095	0.094
	Volume	$/kWh	n/a	n/a	0.07175	0.07354	0.07538
Demand Controlled West (WDC)	Fixed	$/day	n/a	n/a	0.118	0.119	0.119
	Volume	$/kWh	n/a	n/a	0.30750	0.31518	0.32306
Demand Controlled Mount Isa (MDC)	Fixed	$/day	n/a	n/a	0.126	0.128	0.127
	Volume	$/kWh	n/a	n/a	0.07175	0.07354	0.07538
Unmetered supply							
Unmetered supply							
Unmetered Supply East (EVU, EVUMI, EVUMA)	Fixed	$/day/device	0.006	0.007	0.006	0.006	0.006
	Volume	$/kWh	0.16612	0.17797	0.18242	0.18698	0.19165
Unmetered Supply West (WVU, WVUMI, WVUMA)	Fixed	$/day/device	0.276	0.316	0.270	0.275	0.273
	Volume	$/kWh	0.13659	0.17820	0.18265	0.18722	0.19190
Unmetered Supply Mount Isa (MVU, MVUMI, MVUMA)	Fixed	$/day/device	0.229	0.241	0.206	0.210	0.208
	Volume	$/kWh	0.02830	0.01502	0.01539	0.01578	0.01617

Table 7: SAC Large indicative DUOS prices

Tariff	Charging parameter	Units	2015-16	2016-17	2017-18	2018-19	2019-20
SAC Large default tariffs							
Demand High Voltage							
Demand High Voltage East[39] (EDHT)	Fixed	$/day	327.676	350.530	324.637	329.465	330.239
	Actual Demand	$/kW/month	20.581	22.000	20.375	20.678	20.726
	Volume	$/kWh	0.00220	0.00400	0.00370	0.00376	0.00377
Demand Large							
Demand Large East (EDLT)	Fixed	$/day	369.989	374.766	347.083	352.244	353.072
	Actual Demand	$/kW/month	23.268	24.000	22.227	22.558	22.611
	Volume	$/kWh	0.00500	0.00720	0.00667	0.00677	0.00678
Demand Large West (WDLT)	Fixed	$/day	1,182.117	1,189.512	1,101.645	1,118.027	1,120.653
	Actual Demand	$/kW/month	80.000	80.630	74.674	75.785	75.963
	Volume	$/kWh	0.00500	0.01049	0.00972	0.00986	0.00988
Demand Large Mount Isa (MDLT)	Fixed	$/day	246.220	249.488	231.059	234.495	235.046
	Actual Demand	$/kW/month	14.000	15.000	13.892	14.099	14.132
	Volume	$/kWh	0.00400	0.00618	0.00572	0.00581	0.00582
Demand Medium							
Demand Medium East (EDMT)	Fixed	$/day	135.614	137.779	127.602	129.499	129.804
	Actual Demand	$/kW/month	27.151	27.165	25.159	25.533	25.593
	Volume	$/kWh	0.00373	0.00504	0.00467	0.00474	0.00475
Demand Medium West (WDMT)	Fixed	$/day	370.380	379.249	351.235	356.458	357.295
	Actual Demand	$/kW/month	88.605	90.568	83.878	85.126	85.325
	Volume	$/kWh	0.00500	0.00700	0.00648	0.00658	0.00659
Demand Medium Mount Isa (MDMT)	Fixed	$/day	87.340	87.340	80.888	82.091	82.284
	Actual Demand	$/kW/month	17.463	18.764	17.378	17.636	17.678
	Volume	$/kWh	0.00400	0.00575	0.00533	0.00541	0.00542
Demand Small							
Demand Small East (EDST)	Fixed	$/day	37.960	39.670	36.740	37.287	37.374
	Actual Demand	$/kW/month	32.640	34.544	31.993	32.469	32.545
	Volume	$/kWh	0.00416	0.00422	0.00391	0.00397	0.00398

[39] Ergon Energy proposes to continue the phase out of this tariff

Appendix A: Indicative pricing schedule for Standard Control Services

Tariff	Charging parameter	Units	2015-16	2016-17	2017-18	2018-19	2019-20
Demand Small West (WDST)	Fixed	$/day	93.438	94.008	87.064	88.359	88.567
	Actual Demand	$/kW/month	93.048	95.952	88.865	90.186	90.398
	Volume	$/kWh	0.00500	0.00500	0.00463	0.00470	0.00471
Demand Small Mount Isa (MDST)	Fixed	$/day	24.558	24.558	22.744	23.082	23.136
	Actual Demand	$/kW/month	20.666	22.306	20.658	20.965	21.015
	Volume	$/kWh	0.00400	0.00600	0.00556	0.00564	0.00565
SAC Large optional tariffs							
Seasonal TOU Demand							
Seasonal TOU Demand East (ESTOUDC)	Fixed	$/day	32.000	32.000	29.636	30.077	30.148
	Actual Demand Peak	$/kW/month	47.829	53.709	59.080	64.988	71.487
	Actual Demand Off-Peak	$/kW/month	12.936	12.000	11.114	11.279	11.305
	Volume Peak	$/kWh	0.00000	0.00000	0.00000	0.00000	0.00000
	Volume Off-Peak	$/kWh	0.03364	0.03084	0.02856	0.02899	0.02906
Seasonal TOU Demand West (WSTOUDC)	Fixed	$/day	105.000	104.639	96.910	98.351	98.582
	Actual Demand Peak	$/kW/month	119.573	134.528	147.981	162.779	179.057
	Actual Demand Off-Peak	$/kW/month	45.000	44.121	40.862	41.470	41.567
	Volume Peak	$/kWh	0.00000	0.00000	0.00000	0.00000	0.00000
	Volume Off-Peak	$/kWh	0.07422	0.050	0.046	0.047	0.047
Seasonal TOU Demand Mount Isa (MSTOUDC)	Fixed	$/day	24.000	24.000	22.227	22.558	22.611
	Actual Demand Peak	$/kW/month	47.829	53.709	59.080	64.988	71.487
	Actual Demand Off-Peak	$/kW/month	3.611	3.073	2.847	2.889	2.896
	Volume Peak	$/kWh	0.00000	0.00000	0.00000	0.00000	0.00000
	Volume Off-Peak	$/kWh	0.01000	0.01000	0.00926	0.00940	0.00942

Table 8: CAC indicative DUOS prices

Tariff	Charging parameter	Units	2015-16	2016-17	2017-18	2018-19	2019-20
CAC default tariffs							
CAC 66 kV							
CAC 66 kV East (EC66)	Fixed	$/day	133.962	130.366	120.834	122.772	123.275
	Connection Unit	$/day/connection unit	10.888	10.389	9.629	9.783	9.824
	Capacity	$/kVA of AD/month	4.081	4.478	4.151	4.217	4.234
	Actual Demand	$/kVA/month	2.393	2.507	2.323	2.361	2.370
	Volume	$/kWh	0.00534	0.00501	0.00464	0.00472	0.00474
	Excess Reactive Power	$/excess kVAr/month	n/a	0.000	4.000	4.000	4.000
CAC 66 kV West (WC66)	Fixed	$/day	130.016	130.353	120.823	122.760	123.263
	Connection Unit	$/day/connection unit	10.888	10.389	9.629	9.783	9.824
	Capacity	$/kVA of AD/month	12.211	14.038	13.011	13.220	13.274
	Actual Demand	$/kVA/month	550.878	601.632	557.645	566.586	568.908
	Volume	$/kWh	0.01168	0.01403	0.01301	0.01322	0.01327
	Excess Reactive Power	$/excess kVAr/month	n/a	0.000	4.000	4.000	4.000
CAC 66 kV Mount Isa (MC66)	Fixed	$/day	POA	POA	POA	POA	POA
	Connection Unit	$/day/connection unit	POA	POA	POA	POA	POA
	Capacity	$/kVA of AD/month	POA	POA	POA	POA	POA
	Actual Demand	$/kVA/month	POA	POA	POA	POA	POA
	Volume	$/kWh	POA	POA	POA	POA	POA
	Excess Reactive Power	$/excess kVAr/month	n/a	POA	POA	POA	POA
CAC 33 kV							
CAC 33 kV East (EC33)	Fixed	$/day	61.708	62.174	57.628	58.552	58.792
	Connection Unit	$/day/connection unit	10.888	10.389	9.629	9.783	9.824
	Capacity	$/kVA of AD/month	5.195	5.021	4.654	4.729	4.748
	Actual Demand	$/kVA/month	3.530	3.710	3.439	3.494	3.508
	Volume	$/kWh	0.00534	0.00501	0.00464	0.00472	0.00474
	Excess Reactive Power	$/excess kVAr/month	n/a	0.000	4.000	4.000	4.000
CAC 33 kV West (WC33)	Fixed	$/day	57.762	61.165	56.693	57.602	57.839
	Connection Unit	$/day/connection unit	10.888	10.389	9.629	9.783	9.824

Appendix A: Indicative pricing schedule for Standard Control Services

Tariff	Charging parameter	Units	2015-16	2016-17	2017-18	2018-19	2019-20
	Capacity	$/kVA of AD/month	20.598	23.062	21.376	21.719	21.808
	Actual Demand	$/kVA/month	30.158	27.073	25.094	25.496	25.600
	Volume	$/kWh	0.01168	0.01403	0.01301	0.01322	0.01327
	Excess Reactive Power	$/excess kVAr/month	n/a	0.000	4.000	4.000	4.000
CAC 33 kV Mount Isa (MC33)	Fixed	$/day	POA	POA	POA	POA	POA
	Connection Unit	$/day/connection unit	POA	POA	POA	POA	POA
	Capacity	$/kVA of AD/month	POA	POA	POA	POA	POA
	Actual Demand	$/kVA/month	POA	POA	POA	POA	POA
	Volume	$/kWh	POA	POA	POA	POA	POA
	Excess Reactive Power	$/excess kVAr/month	n/a	POA	POA	POA	POA
CAC 22/11 kV Bus							
CAC 22/11 kV Bus East (EC22B)	Fixed	$/day	47.678	49.137	45.545	46.275	46.465
	Connection Unit	$/day/connection unit	10.888	10.389	9.629	9.783	9.824
	Capacity	$/kVA of AD/month	6.128	6.223	5.768	5.860	5.884
	Actual Demand	$/kVA/month	3.597	3.509	3.253	3.305	3.318
	Volume	$/kWh	0.00534	0.00501	0.00464	0.00472	0.00474
	Excess Reactive Power	$/excess kVAr/month	n/a	0.000	4.000	4.000	4.000
CAC 22/11 kV Bus West (WC22B)	Fixed	$/day	POA	POA	POA	POA	POA
	Connection Unit	$/day/connection unit	POA	POA	POA	POA	POA
	Capacity	$/kVA of AD/month	POA	POA	POA	POA	POA
	Actual Demand	$/kVA/month	POA	POA	POA	POA	POA
	Volume	$/kWh	POA	POA	POA	POA	POA
	Excess Reactive Power	$/excess kVAr/month	n/a	POA	POA	POA	POA
CAC 22/11 kV Bus Mount Isa (MC22B)	Fixed	$/day	POA	POA	POA	POA	POA
	Connection Unit	$/day/connection unit	POA	POA	POA	POA	POA
	Capacity	$/kVA of AD/month	POA	POA	POA	POA	POA
	Actual Demand	$/kVA/month	POA	POA	POA	POA	POA
	Volume	$/kWh	POA	POA	POA	POA	POA
	Excess Reactive Power	$/excess kVAr/month	n/a	POA	POA	POA	POA
CAC 22/11 kV Line							
CAC 22/11 kV Line East (EC22L)	Fixed	$/day	39.397	39.109	36.250	36.831	36.982
	Connection Unit	$/day/connection unit	10.888	10.389	9.629	9.783	9.824
	Capacity	$/kVA of AD/month	12.961	12.535	11.618	11.805	11.853
	Actual Demand	$/kVA/month	7.198	7.019	6.506	6.610	6.637

Appendix A: Indicative pricing schedule for Standard Control Services

Tariff	Charging parameter	Units	2015-16	2016-17	2017-18	2018-19	2019-20
	Volume	$/kWh	0.00534	0.00501	0.00464	0.00472	0.00474
	Excess Reactive Power	$/excess kVAr/month	n/a	0.000	4.000	4.000	4.000
CAC 22/11 kV Line West (WC22L)	Fixed	$/day	35.451	40.108	37.176	37.772	37.927
	Connection Unit	$/day/connection unit	10.888	10.389	9.629	9.783	9.824
	Capacity	$/kVA of AD/month	29.188	32.087	29.741	30.217	30.341
	Actual Demand	$/kVA/month	40.770	36.280	33.628	34.167	34.307
	Volume	$/kWh	0.01168	0.01403	0.01301	0.01322	0.01327
	Excess Reactive Power	$/excess kVAr/month	n/a	0.000	4.000	4.000	4.000
CAC 22/11 kV Line Mount Isa (MC22L)	Fixed	$/day	POA	POA	POA	POA	POA
	Connection Unit	$/day/connection unit	POA	POA	POA	POA	POA
	Capacity	$/kVA of AD/month	POA	POA	POA	POA	POA
	Actual Demand	$/kVA/month	POA	POA	POA	POA	POA
	Volume	$/kWh	POA	POA	POA	POA	POA
	Excess Reactive Power	$/excess kVAr/month	n/a	POA	POA	POA	POA
CAC optional tariffs							
Seasonal TOU Demand Higher Voltage							
Seasonal TOU Demand CAC Higher Voltage East (66/33 kV) (EC66TOU)	Fixed	$/day	0.000	0.000	0.000	0.000	0.000
	Connection Unit	$/day/connection unit	10.888	10.389	9.629	9.783	9.824
	Capacity Peak	$/kVA of AD/month	16.666	n/a	n/a	n/a	n/a
	Actual Demand Off-Peak	$/kVA/month	6.358	n/a	n/a	n/a	n/a
	Capacity	$/kVA of AD/month	n/a	6.016	5.576	5.666	5.689
	Actual Demand Peak	$/kVA/month	n/a	11.000	11.000	11.000	11.000
	Volume Peak	$/kWh	0.00000	0.00000	0.00000	0.00000	0.00000
	Volume Off-Peak	$/kWh	0.04757	0.00401	0.00371	0.00377	0.00379
	Excess Reactive Power	$/excess kVAr/month	n/a	0.000	4.000	4.000	4.000
Seasonal TOU Demand CAC Higher Voltage West (66/33 kV) (WC66TOU)	Fixed	$/day	0.000	0.000	0.000	0.000	0.000
	Connection Unit	$/day/connection unit	10.888	10.389	9.629	9.783	9.824
	Capacity Peak	$/kVA of AD/month	83.333	n/a	n/a	n/a	n/a
	Actual Demand Off-Peak	$/kVA/month	73.483	n/a	n/a	n/a	n/a
	Capacity	$/kVA of AD/month	n/a	20.258	18.777	19.078	19.156
	Actual Demand Peak	$/kVA/month	n/a	27.666	27.666	27.666	27.666
	Volume Peak	$/kWh	0.00000	0.00000	0.00000	0.00000	0.00000
	Volume Off-Peak	$/kWh	0.26229	0.03008	0.02788	0.02832	0.02844
	Excess Reactive Power	$/excess kVAr/month	n/a	0.000	4.000	4.000	4.000

Appendix A: Indicative pricing schedule for Standard Control Services

Tariff	Charging parameter	Units	2015-16	2016-17	2017-18	2018-19	2019-20
Seasonal TOU Demand CAC Higher Voltage Mount Isa (66/33 kV) (MC66TOU)	Fixed	$/day	POA	POA	POA	POA	POA
	Connection Unit	$/day/connection unit	POA	POA	POA	POA	POA
	Capacity Peak	$/kVA of AD/month	POA	n/a	n/a	n/a	n/a
	Actual Demand Off-Peak	$/kVA/month	POA	n/a	n/a	n/a	n/a
	Capacity	$/kVA of AD/month	n/a	POA	POA	POA	POA
	Actual Demand Peak	$/kVA/month	n/a	POA	POA	POA	POA
	Volume Peak	$/kWh	POA	POA	POA	POA	POA
	Volume Off-Peak	$/kWh	POA	POA	POA	POA	POA
	Excess Reactive Power	$/excess kVAr/month	n/a	POA	POA	POA	POA
Seasonal TOU Demand CAC 22/11 kV Bus							
Seasonal TOU Demand CAC 22/11 kV Bus East (EC22BTOU)	Fixed	$/day	0.000	0.000	0.000	0.000	0.000
	Connection Unit	$/day/connection unit	10.888	10.389	9.629	9.783	9.824
	Capacity Peak	$/kVA of AD/month	33.333	n/a	n/a	n/a	n/a
	Actual Demand Off-Peak	$/kVA/month	6.358	n/a	n/a	n/a	n/a
	Capacity	$/kVA of AD/month	n/a	4.011	3.717	3.777	3.793
	Actual Demand Peak	$/kVA/month	n/a	36.665	40.331	43.998	43.998
	Volume Peak	$/kWh	0.00000	0.00000	0.00000	0.00000	0.00000
	Volume Off-Peak	$/kWh	0.04757	0.00401	0.00371	0.00377	0.00379
	Excess Reactive Power	$/excess kVAr/month	n/a	0.000	4.000	4.000	4.000
Seasonal TOU Demand CAC 22/11 kV Bus West (WC22BTOU)	Fixed	$/day	POA	POA	POA	POA	POA
	Connection Unit	$/day/connection unit	POA	POA	POA	POA	POA
	Capacity Peak	$/kVA of AD/month	POA	n/a	n/a	n/a	n/a
	Actual Demand Off-Peak	$/kVA/month	POA	n/a	n/a	n/a	n/a
	Capacity	$/kVA of AD/month	n/a	POA	POA	POA	POA
	Actual Demand Peak	$/kVA/month	n/a	POA	POA	POA	POA
	Volume Peak	$/kWh	POA	POA	POA	POA	POA
	Volume Off-Peak	$/kWh	POA	POA	POA	POA	POA
	Excess Reactive Power	$/excess kVAr/month	n/a	POA	POA	POA	POA

Appendix A: Indicative pricing schedule for Standard Control Services

Tariff	Charging parameter	Units	2015-16	2016-17	2017-18	2018-19	2019-20
Seasonal TOU Demand CAC 22/11 kV Bus Mount Isa (MC22BTOU)	Fixed	$/day	POA	POA	POA	POA	POA
	Connection Unit	$/day/connection unit	POA	POA	POA	POA	POA
	Capacity Peak	$/kVA of AD/month	POA	n/a	n/a	n/a	n/a
	Actual Demand Off-Peak	$/kVA/month	POA	n/a	n/a	n/a	n/a
	Capacity	$/kVA of AD/month	n/a	POA	POA	POA	POA
	Actual Demand Peak	$/kVA/month	n/a	POA	POA	POA	POA
	Volume Peak	$/kWh	POA	POA	POA	POA	POA
	Volume Off-Peak	$/kWh	POA	POA	POA	POA	POA
	Excess Reactive Power	$/excess kVAr/month	n/a	POA	POA	POA	POA
Seasonal TOU Demand CAC 22/11 kV Line							
Seasonal TOU Demand CAC 22/11 kV Line East (EC22LTOU)	Fixed	$/day	0.000	0.000	0.000	0.000	0.000
	Connection Unit	$/day/connection unit	10.888	10.389	9.629	9.783	9.824
	Capacity Peak	$/kVA of AD/month	48.166	n/a	n/a	n/a	n/a
	Actual Demand Off-Peak	$/kVA/month	13.358	n/a	n/a	n/a	n/a
	Capacity	$/kVA of AD/month	n/a	9.573	8.873	9.015	9.052
	Actual Demand Peak	$/kVA/month	n/a	72.333	72.333	72.333	72.333
	Volume Peak	$/kWh	0.00000	0.00000	0.00000	0.00000	0.00000
	Volume Off-Peak	$/kWh	0.04757	0.00401	0.00371	0.00377	0.00379
	Excess Reactive Power	$/excess kVAr/month	n/a	0.000	4.000	4.000	4.000
Seasonal TOU Demand CAC 22/11 kV Line West (WC22LTOU)	Fixed	$/day	0.000	0.000	0.000	0.000	0.000
	Connection Unit	$/day/connection unit	10.888	10.389	9.629	9.783	9.824
	Capacity Peak	$/kVA of AD/month	240.833	n/a	n/a	n/a	n/a
	Actual Demand Off-Peak	$/kVA/month	50.897	n/a	n/a	n/a	n/a
	Capacity	$/kVA of AD/month	n/a	36.097	33.458	33.995	34.134
	Actual Demand Peak	$/kVA/month	n/a	181.000	181.000	181.000	181.000
	Volume Peak	$/kWh	0.00000	0.00000	0.00000	0.00000	0.00000
	Volume Off-Peak	$/kWh	0.15229	0.03008	0.02788	0.02832	0.02844
	Excess Reactive Power	$/excess kVAr/month	n/a	0.000	4.000	4.000	4.000

Appendix A: Indicative pricing schedule for Standard Control Services

Tariff	Charging parameter	Units	2015-16	2016-17	2017-18	2018-19	2019-20
Seasonal TOU Demand CAC 22/11 kV Line Mount Isa (MC22LTOU)	Fixed	$/day	POA	POA	POA	POA	POA
	Connection Unit	$/day/connection unit	POA	POA	POA	POA	POA
	Capacity Peak	$/kVA of AD/month	POA	n/a	n/a	n/a	n/a
	Actual Demand Off-Peak	$/kVA/month	POA	n/a	n/a	n/a	n/a
	Capacity	$/kVA of AD/month	n/a	POA	POA	POA	POA
	Actual Demand Peak	$/kVA/month	n/a	POA	POA	POA	POA
	Volume Peak	$/kWh	POA	POA	POA	POA	POA
	Volume Off-Peak	$/kWh	POA	POA	POA	POA	POA
	Excess Reactive Power	$/excess kVAr/month	n/a	POA	POA	POA	POA

Table 9: ICC indicative DUOS prices – Average[a]

Tariff	Charging parameter	Units	2015-16	2016-17	2017-18	2018-19	2019-20
ICC default tariffs							
ICC 132/110 kV							
ICC 132/110 kV East	Fixed	$/day	1,205.588	1161.067	1074.859	1093.072	1097.718
	Capacity	$/kVA of AD/month	1.088	0.967	0.896	0.911	0.915
	Actual Demand	$/kVA/month	0.824	0.706	0.653	0.664	0.667
	Volume	$/kWh	0.00513	0.00531	0.00492	0.00500	0.00502
	Excess Reactive Power	$/excess kVAr/month	4.000	4.000	4.000	4.000	4.000
ICC 132/110 kV West	Fixed	$/day	401.715	427.245	395.523	402.225	403.934
	Capacity	$/kVA of AD/month	3.117	3.104	2.873	2.922	2.934
	Actual Demand	$/kVA/month	2.642	2.256	2.088	2.124	2.133
	Volume	$/kWh	0.01142	0.01149	0.01064	0.01082	0.01087
	Excess Reactive Power	$/excess kVAr/month	4.000	4.000	4.000	4.000	4.000
ICC 132/110 kV Mount Isa	Fixed	$/day	POA	POA	POA	POA	POA
	Capacity	$/kVA of AD/month	POA	POA	POA	POA	POA
	Actual Demand	$/kVA/month	POA	POA	POA	POA	POA
	Volume	$/kWh	POA	POA	POA	POA	POA
	Excess Reactive Power	$/excess kVAr/month	POA	POA	POA	POA	POA

Appendix A: Indicative pricing schedule for Standard Control Services

Tariff	Charging parameter	Units	2015-16	2016-17	2017-18	2018-19	2019-20
ICC 66 kV							
ICC 66 kV East	Fixed	$/day	521.580	509.901	472.041	480.040	482.080
	Capacity	$/kVA of AD/month	0.426	0.406	0.376	0.382	0.384
	Actual Demand	$/kVA/month	0.280	0.261	0.242	0.246	0.247
	Volume	$/kWh	0.00414	0.00421	0.00390	0.00397	0.00398
	Excess Reactive Power	$/excess kVAr/month	4.000	4.000	4.000	4.000	4.000
ICC 66 kV West	Fixed	$/day	363.004	384.307	355.773	361.801	363.339
	Capacity	$/kVA of AD/month	4.036	3.619	3.350	3.407	3.421
	Actual Demand	$/kVA/month	3.008	2.824	2.614	2.659	2.670
	Volume	$/kWh	0.01084	0.01062	0.00983	0.00999	0.01004
	Excess Reactive Power	$/excess kVAr/month	4.000	4.000	4.000	4.000	4.000
ICC 66 kV Mount Isa	Fixed	$/day	POA	POA	POA	POA	POA
	Capacity	$/kVA of AD/month	POA	POA	POA	POA	POA
	Actual Demand	$/kVA/month	POA	POA	POA	POA	POA
	Volume	$/kWh	POA	POA	POA	POA	POA
	Excess Reactive Power	$/excess kVAr/month	POA	POA	POA	POA	POA
ICC 33 kV							
ICC 33 kV East	Fixed	$/day	274.057	273.532	253.222	257.513	258.608
	Capacity	$/kVA of AD/month	0.451	0.525	0.486	0.494	0.497
	Actual Demand	$/kVA/month	0.338	0.305	0.282	0.287	0.288
	Volume	$/kWh	0.00399	0.00423	0.00391	0.00398	0.00400
	Excess Reactive Power	$/excess kVAr/month	4.000	4.000	4.000	4.000	4.000
ICC 33 kV West	Fixed	$/day	226.596	256.013	237.005	241.020	242.045
	Capacity	$/kVA of AD/month	3.624	3.717	3.441	3.499	3.514
	Actual Demand	$/kVA/month	2.491	2.416	2.237	2.274	2.284
	Volume	$/kWh	0.01533	0.01384	0.01281	0.01303	0.01308
	Excess Reactive Power	$/excess kVAr/month	4.00	4.000	4.000	4.000	4.000
ICC 33 kV Mount Isa	Fixed	$/day	POA	POA	POA	POA	POA
	Capacity	$/kVA of AD/month	POA	POA	POA	POA	POA
	Actual Demand	$/kVA/month	POA	POA	POA	POA	POA
	Volume	$/kWh	POA	POA	POA	POA	POA
	Excess Reactive Power	$/excess kVAr/month	POA	POA	POA	POA	POA

Appendix A: Indicative pricing schedule for Standard Control Services

Tariff	Charging parameter	Units	2015-16	2016-17	2017-18	2018-19	2019-20
ICC 22/11 kV Bus							
ICC 22/11 kV Bus East	Fixed	$/day	347.208	341.840	316.459	321.821	323.189
	Capacity	$/kVA of AD/month	2.525	2.401	2.223	2.260	2.270
	Actual Demand	$/kVA/month	1.682	1.556	1.441	1.465	1.472
	Volume	$/kWh	0.00507	0.00510	0.00472	0.00480	0.00483
	Excess Reactive Power	$/excess kVAr/month	4.000	4.000	4.000	4.000	4.000
ICC 22/11 kV Bus West	Fixed	$/day	651.438	656.354	607.620	617.916	620.543
	Capacity	$/kVA of AD/month	3.792	3.258	3.016	3.067	3.080
	Actual Demand	$/kVA/month	2.122	1.818	1.683	1.712	1.719
	Volume	$/kWh	0.01278	0.01259	0.01166	0.01185	0.01191
	Excess Reactive Power	$/excess kVAr/month	4.000	4.000	4.000	4.000	4.000
ICC 22/11 kV Bus Mount Isa	Fixed	$/day	POA	POA	POA	POA	POA
	Capacity	$/kVA of AD/month	POA	POA	POA	POA	POA
	Actual Demand	$/kVA/month	POA	POA	POA	POA	POA
	Volume	$/kWh	POA	POA	POA	POA	POA
	Excess Reactive Power	$/excess kVAr/month	POA	POA	POA	POA	POA

Notes:

a) ICC DUOS pricing is carried out with specific reference to individual customers and associated network connection configuration and arrangements. Outcomes are specific to those individual circumstances and changes that may occur to them. Indicative prices are calculated on an average basis and therefore are indicative only of future trends in prices at a macro level based on our current estimates of future DUOS charges.

2 TUOS indicative prices

Table 10: SAC Small indicative TUOS prices – Primary tariffs[a]

Transmission pricing region	TUOS tariff	TUOS charge	Units	2015-16	2016-17	2017-18	2018-19	2019-20
Transmission Region 1	T1	Fixed	$/day	0.137	0.144	0.106	0.106	0.107
		Volume	$/kWh	0.01378	0.01505	0.01134	0.01159	0.01194
Transmission Region 2	T2	Fixed	$/day	0.255	0.294	0.217	0.217	0.219
		Volume	$/kWh	0.01632	0.01804	0.01360	0.01389	0.01431
Transmission Region 3	T3	Fixed	$/day	0.308	0.410	0.302	0.303	0.305
		Volume	$/kWh	0.02102	0.02259	0.01703	0.01740	0.01792
Transmission Region 4[b]	T4	Fixed	$/day	0.121	0.135	0.138	0.128	0.129
		Volume	$/kWh	0.00059	0.00073	0.00076	0.00072	0.00074

Notes:

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

Table 11: SAC Small indicative TUOS prices – Secondary and unmetered tariffs[a]

Transmission pricing region	TUOS tariff	TUOS charge	Units	2015-16	2016-17	2017-18	2018-19	2019-20
Transmission Region 1	T1	Volume	$/kWh	0.01378	0.01505	0.01134	0.01159	0.01194
Transmission Region 2	T2	Volume	$/kWh	0.01632	0.01804	0.01360	0.01389	0.01431
Transmission Region 3	T3	Volume	$/kWh	0.02102	0.02259	0.01703	0.01740	0.01792
Transmission Region 4	T4	Volume	$/kWh	0.00059	0.00073	0.00076	0.00072	0.00074

Notes:

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

Table 12: SAC Large indicative TUOS prices

Transmission pricing region	TUOS tariff	TUOS charge	Units	2015-16	2016-17	2017-18	2018-19	2019-20
Demand HV and Demand Large								
Transmission Region 1	T1	Fixed	$/day	19.897	17.978	13.513	13.748	14.102
		Actual Demand	$/kW/month	1.245	1.072	0.806	0.820	0.841
		Volume	$/kWh	0.01378	0.01505	0.01138	0.01157	0.01186
Transmission Region 2	T2	Fixed	$/day	36.568	43.363	32.593	33.159	34.015
		Actual Demand	$/kW/month	2.440	2.913	2.189	2.227	2.285
		Volume	$/kWh	0.01632	0.01804	0.01364	0.01387	0.01422
Transmission Region 3	T3	Fixed	$/day	69.216	77.399	58.176	59.187	60.714
		Actual Demand	$/kW/month	4.938	5.487	4.124	4.196	4.304
		Volume	$/kWh	0.02102	0.02259	0.01708	0.01737	0.01780
Transmission Region 4 (Demand Large Only)	T4	Fixed	$/day	11.227	11.374	11.740	11.001	11.138
		Actual Demand	$/kW/month	0.641	0.647	0.667	0.625	0.633
		Volume	$/kWh	0.00059	0.00073	0.00076	0.00072	0.00074
Demand Medium								
Transmission Region 1	T1	Fixed	$/day	8.437	8.113	6.098	6.204	6.364
		Actual Demand	$/kW/month	1.245	1.072	0.806	0.820	0.841
		Volume	$/kWh	0.01378	0.01505	0.01138	0.01157	0.01186
Transmission Region 2	T2	Fixed	$/day	14.116	16.564	12.450	12.667	12.994
		Actual Demand	$/kW/month	2.440	2.913	2.189	2.227	2.285
		Volume	$/kWh	0.01632	0.01804	0.01364	0.01387	0.01422
Transmission Region 3	T3	Fixed	$/day	23.790	26.914	20.229	20.581	21.112
		Actual Demand	$/kW/month	4.938	5.487	4.124	4.196	4.304
		Volume	$/kWh	0.02102	0.02259	0.01708	0.01737	0.01780
Transmission Region 4	T4	Fixed	$/day	5.326	5.421	5.595	5.243	5.308
		Actual Demand	$/kW/month	0.641	0.647	0.667	0.625	0.633
		Volume	$/kWh	0.00059	0.00073	0.00076	0.00072	0.00074
Demand Small								
Transmission Region 1	T1	Fixed	$/day	4.754	4.942	3.714	3.779	3.876
		Actual Demand	$/kW/month	1.245	1.072	0.806	0.820	0.841
		Volume	$/kWh	0.01378	0.01505	0.01138	0.01157	0.01186

Appendix A: Indicative pricing schedule for Standard Control Services

Transmission pricing region	TUOS tariff	TUOS charge	Units	2015-16	2016-17	2017-18	2018-19	2019-20
Transmission Region 2	T2	Fixed	$/day	6.899	7.951	5.976	6.080	6.237
		Actual Demand	$/kW/month	2.440	2.913	2.189	2.227	2.285
		Volume	$/kWh	0.01632	0.01804	0.01364	0.01387	0.01422
Transmission Region 3	T3	Fixed	$/day	9.189	10.687	8.032	8.172	8.383
		Actual Demand	$/kW/month	4.938	5.487	4.124	4.196	4.304
		Volume	$/kWh	0.02102	0.02259	0.01708	0.01737	0.01780
Transmission Region 4	T4	Fixed	$/day	3.429	3.507	3.620	3.392	3.434
		Actual Demand	$/kW/month	0.641	0.647	0.667	0.625	0.633
		Volume	$/kWh	0.00059	0.00073	0.00076	0.00072	0.00074
Seasonal Time-of-Use Demand								
Transmission Region 1	T1	Fixed	$/day	4.958	5.118	3.847	3.914	4.015
		Actual Demand Peak	$/kW/month	1.245	1.072	0.806	0.820	0.841
		Actual Demand Off-Peak	$/kW/month	1.245	1.072	0.806	0.820	0.841
		Volume	$/kWh	0.01378	0.01505	0.01138	0.01157	0.01186
Transmission Region 2	T2	Fixed	$/day	7.300	8.429	6.336	6.446	6.612
		Actual Demand Peak	$/kW/month	2.440	2.913	2.189	2.227	2.285
		Actual Demand Off-Peak	$/kW/month	2.440	2.913	2.189	2.227	2.285
		Volume	$/kWh	0.01632	0.01804	0.01364	0.01387	0.01422
Transmission Region 3	T3	Fixed	$/day	10.000	11.588	8.710	8.861	9.090
		Actual Demand Peak	$/kW/month	4.938	5.487	4.124	4.196	4.304
		Actual Demand Off-Peak	$/kW/month	4.938	5.487	4.124	4.196	4.304
		Volume	$/kWh	0.02102	0.02259	0.01708	0.01737	0.01780
Transmission Region 4	T4	Fixed	$/day	3.535	3.613	3.729	3.495	3.538
		Actual Demand Peak	$/kW/month	0.641	0.647	0.667	0.625	0.633
		Actual Demand Off-Peak	$/kW/month	0.641	0.647	0.667	0.625	0.633
		Volume	$/kWh	0.00059	0.00073	0.00076	0.00072	0.00074

Appendix A: Indicative pricing schedule for Standard Control Services

Table 13: CAC indicative TUOS prices – All tariffs

Transmission pricing region	TUOS tariff	TUOS charge	Units	2015-16	2016-17	2017-18	2018-19	2019-20
Transmission Region 1	T1	Fixed	$/day	125.204	136.765	104.136	105.709	108.196
		Capacity	$/kVA of AD/month	1.236	0.939	0.715	0.726	0.743
		Volume	$/kWh	0.01331	0.01436	0.01084	0.01100	0.01126
Transmission Region 2	T2	Fixed	$/day	88.108	96.524	73.496	74.606	76.362
		Capacity	$/kVA of AD/month	2.196	2.424	1.846	1.874	1.918
		Volume	$/kWh	0.01592	0.01731	0.01307	0.01327	0.01358
Transmission Region 3	T3	Fixed	$/day	84.490	104.588	79.636	80.839	82.741
		Capacity	$/kVA of AD/month	4.280	4.767	3.629	3.684	3.771
		Volume	$/kWh	0.02123	0.02249	0.01698	0.01724	0.01764

Table 14: ICC indicative TUOS prices – Averaged (not customer-specific) – All tariffs[b]

Customer pricing zone	Voltage level	TUOS charge	Units	2015-16	2016-17	2017-18	2018-19	2019-20
East	132/110 kV	Fixed	$/day	861.174	847.280	634.564	644.151	659.306
		Capacity	$/kVA of AD/month	1.997	2.323	1.740	1.766	1.807
		Volume	$/kWh	0.00350	0.00397	0.00298	0.00302	0.00309
		General & Common Service	$/day	740.955	786.145	588.778	597.673	611.734
East	66 kV	Fixed	$/day	443.039	466.020	349.022	354.295	362.631
		Capacity	$/kVA of AD/month	1.170	1.196	0.896	0.910	0.931
		Volume	$/kWh	0.00258	0.00298	0.00223	0.00226	0.00232
		General & Common Service	$/day	2,265.352	2,308.326	1,728.804	1,754.924	1,796.211
East	33 kV	Fixed	$/day	721.944	741.835	555.592	563.986	577.255
		Capacity	$/kVA of AD/month	1.596	1.994	1.493	1.516	1.551
		Volume	$/kWh	0.00202	0.00440	0.00330	0.00335	0.00343
		General & Common Service	$/day	3,276.919	2,241.000	1,678.380	1,703.738	1,743.821
East	22/11 kV Bus	Fixed	$/day	120.750	141.744	106.158	107.762	110.297
		Capacity	$/kVA of AD/month	1.723	2.249	1.684	1.710	1.750
		Volume	$/kWh	0.00376	0.00411	0.00308	0.00313	0.00320
		General & Common Service	$/day	768.646	897.538	672.205	682.361	698.414

Appendix A: Indicative pricing schedule for Standard Control Services

Customer pricing zone	Voltage level	TUOS charge	Units	2015-16	2016-17	2017-18	2018-19	2019-20
West	132/110 kV	Fixed	$/day	593.125	765.513	573.325	581.988	595.680
		Capacity	$/kVA of AD/month	1.058	1.388	1.039	1.055	1.080
		Volume	$/kWh	0.00184	0.00198	0.00148	0.00151	0.00154
		General & Common Service	$/day	987.708	872.031	653.101	662.969	678.566
West	66 kV	Fixed	$/day	180.749	189.280	141.760	143.901	147.287
		Capacity	$/kVA of AD/month	1.429	1.583	1.185	1.203	1.231
		Volume	$/kWh	0.00314	0.00363	0.00272	0.00276	0.00283
		General & Common Service	$/day	1,363.367	1,261.732	944.965	959.242	981.810
West	33 kV	Fixed	$/day	290.019	361.696	270.890	274.982	281.452
		Capacity	$/kVA of AD/month	0.962	0.934	0.699	0.710	0.726
		Volume	$/kWh	0.00127	0.00115	0.00086	0.00087	0.00089
		General & Common Service	$/day	347.045	503.395	377.014	382.710	391.714
West	22/11 kV Bus	Fixed	$/day	117.857	125.966	94.341	95.767	98.020
		Capacity	$/kVA of AD/month	1.897	2.074	1.553	1.577	1.614
		Volume	$/kWh	0.00430	0.00450	0.00337	0.00342	0.00350
		General & Common Service	$/day	608.802	663.567	496.974	504.482	516.351

Notes:

a) ICC TUOS pricing is carried out with specific reference to individual customers and associated network connection configuration and arrangements. Outcomes are specific to those individual circumstances and changes that may occur to them. Indicative prices are calculated on an average basis and therefore are indicative only of future trends in prices at a macro level based on our current estimates of future TUOS charges.

Appendix A: Indicative pricing schedule for Standard Control Services

Table 15: Standard DLFs applicable in 2016-17[a]

Network Level	East	West	Mount Isa
Sub-transmission Bus	1.006	1.028	1.001
Sub-transmission Line	1.011	1.062	1.006
22/11 kV Bus	1.015	1.068	1.008
22/11 kV Line	1.028	1.100	1.036
LV Bus	1.074	1.154	1.065
LV Line	1.095	1.185	1.069

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.

3 Indicative jurisdictional scheme charges

Table 16: Indicative jurisdictional scheme charges[a]

Customer group	Charge	Units	2015-16	2016-17	2017-18	2018-19	2019-20
SAC Small – Primary tariffs	Fixed	$/day	0.184	0.166	0.178	0.153	0.146
	Volume	$/kWh	0.01176	0.01012	0.01108	0.00975	0.00950
SAC Small – Controlled load tariffs	Volume	$/kWh	0.00000	0.01012	0.01108	0.00975	0.00950
SAC Large	Fixed	$/day	0.762	0.893	0.970	0.850	0.825
	Volume	$/kWh	0.00179	0.00131	0.00144	0.00126	0.00122
CAC	Fixed	$/day	25.403	16.752	18.495	16.236	15.773
	Volume	$/kWh	0.00117	0.00083	0.00090	0.00079	0.00077
ICC	Fixed	$/day	146.903	134.118	146.568	128.538	124.752

Notes:

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

4 Further information

Ergon Energy publishes a *Network Tariff Guide for Standard Control Services* which sets out detailed information on each of our network tariffs, including the application rules. Network users, retailers and interested parties seeking to understand the application of our tariffs are encouraged to refer to this publication which is available on Ergon Energy's website at:

https://www.ergon.com.au/network/network-management/network-pricing

Appendix B Indicative pricing schedule for Alternative Control Services

This appendix sets out indicative prices for our ACS for the 2017 to 2020 period. These prices are based on the tariff structures detailed in our TSS and currently available information.

1 Fee based services

Table 17: Indicative fee based services prices

Service	2016-17 GST Exclusive		2017-18 GST Exclusive		2018-19 GST Exclusive		2019-20 GST Exclusive	
	Total price[a]	Call out fee[b]	Total price	Call out fee	Total price	Call out fee	Total price	Call out fee
Application fee - Basic or standard connection	$870.18	n/a	$890.55	n/a	$912.75	n/a	$936.90	n/a
Application fee - Basic or standard connection - Micro-embedded generators	$47.60	n/a	$48.72	n/a	$49.93	n/a	$51.25	n/a
Application fee - Basic or standard connection - Micro-embedded generators - Technical assessment required	$216.17	n/a	$221.23	n/a	$226.74	n/a	$232.74	n/a
Application fee - Real estate development connection	$911.10	n/a	$932.42	n/a	$955.67	n/a	$980.95	n/a
Protection and Power Quality assessment prior to connection	$1,348.46	n/a	$1,380.02	n/a	$1,414.43	n/a	$1,451.85	n/a
Temporary connection, not in permanent position - single phase metered - urban/short rural feeders	$572.95	$114.59	$586.36	$117.27	$600.98	$120.20	$616.88	$123.38
Temporary connection, not in permanent position - single phase metered - long rural/isolated feeders	$916.72	$458.36	$938.17	$469.09	$961.56	$480.78	$987.00	$493.50
Temporary connection, not in permanent position - multi phase metered - urban/short rural feeders	$572.95	$114.59	$586.36	$117.27	$600.98	$120.20	$616.88	$123.38
Temporary connection, not in permanent position - multi phase metered - long rural/isolated feeders	$916.72	$458.36	$938.17	$469.09	$961.56	$480.78	$987.00	$493.50
Supply abolishment during business - urban/short rural feeders	$343.77	$114.59	$351.82	$117.27	$360.59	$120.20	$370.13	$123.38

Appendix B: Indicative pricing schedule for Alternative Control Services

Service	2016-17 GST Exclusive		2017-18 GST Exclusive		2018-19 GST Exclusive		2019-20 GST Exclusive	
	Total price[a]	Call out fee[b]	Total price	Call out fee	Total price	Call out fee	Total price	Call out fee
Supply abolishment during business hours - long rural/isolated feeders	$687.54	$458.36	$703.63	$469.09	$721.17	$480.78	$740.25	$493.50
De-energisation during business hours - urban/short rural feeders	$96.01	$38.17	$98.26	$39.07	$100.71	$40.04	$103.37	$41.10
De-energisation during business hours - long rural/isolated feeders	$572.95	$458.36	$586.36	$469.09	$600.98	$480.78	$616.88	$493.50
Re-energisation during business hours - urban/short rural feeders	$76.35	$38.17	$78.13	$39.07	$80.08	$40.04	$82.20	$41.10
Re-energisation during business hours - long rural/isolated feeders	$533.99	$458.36	$546.49	$469.09	$560.11	$480.78	$574.93	$493.50
Re-energisation during business hours - after de-energisation for debt - urban/short rural feeders	$76.35	$38.17	$78.13	$39.07	$80.08	$40.04	$82.20	$41.10
Re-energisation during business hours - after de-energisation for debt - long rural/isolated feeders	$533.99	$458.36	$546.49	$469.09	$560.11	$480.78	$574.93	$493.50
Accreditation of alternative service providers - real estate developments	$884.93	n/a	$905.64	n/a	$928.22	n/a	$952.78	n/a
Install new or replacement meter (Type 5 and 6) – Single phase – urban/short rural feeder	$338.15	$62.13	$345.24	$63.59	$352.79	$65.17	$360.83	$66.90
Install new or replacement meter (Type 5 and 6) – Single phase – long rural/isolated feeder	$524.25	$248.53	$535.24	$254.34	$546.95	$260.69	$559.42	$267.58
Install new or replacement meter (Type 5 and 6) – Dual element – urban/short rural feeder	$414.17	$62.13	$422.85	$63.59	$432.10	$65.17	$441.95	$66.90
Install new or replacement meter (Type 5 and 6) – Dual element – long rural/isolated feeder	$600.27	$248.53	$612.85	$254.34	$626.26	$260.69	$640.54	$267.58
Install new or replacement meter (Type 5 and 6) – Polyphase – urban/short rural feeder	$520.59	$62.13	$531.50	$63.59	$543.13	$65.17	$555.51	$66.90
Install new or replacement meter (Type 5 and 6) – Polyphase – long rural/isolated feeder	$706.69	$248.53	$721.50	$254.34	$737.29	$260.69	$754.09	$267.58
Install new or replacement meter (CT) – urban/short rural feeder	$2,473.23	$118.88	$2,525.07	$121.67	$2,580.32	$124.70	$2,639.14	$128.00

Appendix B: Indicative pricing schedule for Alternative Control Services

Service	2016-17 GST Exclusive		2017-18 GST Exclusive		2018-19 GST Exclusive		2019-20 GST Exclusive	
	Total price[a]	Call out fee[b]	Total price	Call out fee	Total price	Call out fee	Total price	Call out fee
Install new or replacement meter (CT) – long rural/isolated feeder	$2,829.31	$475.53	$2,888.62	$486.66	$2,951.82	$498.79	$3,019.11	$511.99

Notes:

a) Service undertaken.

b) No service undertaken due to customer/retailer fault.

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 premises 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 18: Potential indicative quoted services prices

Service	2016-17 GST Exclusive	2017-18 GST Exclusive	2018-19 GST Exclusive	2019-20 GST Exclusive
Application fee - Negotiated connection	$1,106.89	$1,133.40	$1,160.42	$1,186.39
Application fee - Negotiated connection – Micro-embedded generators	$491.74	$503.56	$515.61	$526.93
Application fee - Negotiated - Major customer connection	$7,078.02	$7,249.91	$7,420.59	$7,569.75
Carrying out planning studies and analysis relating to connection applications	$2,235.91	$2,290.15	$2,343.79	$2,390.95
Feasibility and concept scoping, including planning and design, for major customer connections	$17,981.16	$18,417.58	$18,850.48	$19,229.43
Tender process	$10,467.92	$10,722.02	$10,974.65	$11,195.07
Pre-connection site inspection	$1,297.77	$1,328.98	$1,359.83	$1,386.76
Provision of site-specific connection information and advice	$765.56	$784.14	$802.55	$818.69
Preparation of preliminary designs and planning reports for major customer connections, including project scopes and estimates	$9,421.13	$9,649.82	$9,877.19	$10,075.56
Customer build, own and operate consultation services	$74,618.80	$76,430.11	$78,230.99	$79,802.18
Detailed enquiry response fee – embedded generation	$24,943.32	$25,548.78	$26,150.62	$26,675.87
Design and construction of connection assets for major customers	$8,866,367.57	$8,943,966.76	$9,150,678.77	$9,302,942.33
Commissioning and energisation of major customer connections	$43,058.66	$44,080.82	$45,086.02	$45,957.84
Design and construction for real estate developments	$169,203.36	$168,703.41	$172,546.45	$175,348.82

Appendix B: Indicative pricing schedule for Alternative Control Services

Service	2016-17 GST Exclusive	2017-18 GST Exclusive	2018-19 GST Exclusive	2019-20 GST Exclusive
Commissioning and energisation of real estate development connections	$6,769.39	$6,713.45	$6,833.75	$6,926.63
Removal of network constraint for embedded generator	$542,736.39	$555,940.71	$570,772.89	$582,766.07
Move point of attachment - single/multi phase	$3,648.49	$3,735.76	$3,818.90	$3,890.24
Re-arrange connection assets at customer's request	$65,860.89	$67,458.04	$69,039.51	$70,427.97
Protection and Power Quality assessment after connection	$2,787.65	$2,854.73	$2,921.03	$2,978.65
Temporary de-energisation - no dismantling	$728.17	$757.34	$774.21	$788.79
LV Service line drop and replace - physical dismantling	$1,055.53	$1,099.44	$1,124.51	$1,146.35
HV Service line drop and replace	$4,456.70	$4,527.27	$4,624.15	$4,706.00
Supply enhancement	$1,273.98	$1,293.57	$1,321.33	$1,344.72
Provision of connection services above minimum requirements	$300,068.02	$304,345.28	$310,852.49	$316,354.19
Upgrade from overhead to underground service	$8,593.83	$8,691.19	$8,869.09	$9,015.85
Rectification of illegal connections or damage to overhead or underground service cables	$214.92	$219.91	$224.75	$228.89
De-energisation after business hours	$141.27	$146.89	$150.15	$152.97
Re-energisation after business hours	$112.33	$116.80	$119.40	$121.64
Accreditation of alternative service providers - major customer connections	$6,265.80	$6,416.34	$6,569.94	$6,714.75
Approval of third party design - major customer connections	$13,957.22	$14,296.02	$14,632.87	$14,926.76
Approval of third party design - real estate developments	$196.40	$201.10	$205.91	$210.54
Construction audit - major customer connections	$90,562.64	$92,740.14	$94,896.44	$96,772.24
Construction audit - real estate developments	$1,152.66	$1,179.58	$1,205.77	$1,228.20
Approval of third party materials	$18,765.73	$19,220.96	$19,671.68	$20,067.35
Special meter read	$125.50	$128.38	$131.19	$133.60
Meter test	$444.17	$454.48	$464.49	$473.03
Meter inspection and investigation on request	$286.56	$293.21	$299.67	$305.18
Metering alteration	$2,833.45	$2,899.22	$2,963.30	$3,018.12

Appendix B: Indicative pricing schedule for Alternative Control Services

Service	2016-17 GST Exclusive	2017-18 GST Exclusive	2018-19 GST Exclusive	2019-20 GST Exclusive
Exchange meter	$286.56	$293.21	$299.67	$305.18
Type 5 to 7 non-standard metering services	$406.32	$416.12	$425.77	$434.22
Removal of a meter (Type 5 & 6)	$135.00	$138.21	$141.35	$144.07
Meter re-seal	$580.28	$593.75	$606.83	$617.99
Install new or replacement meter - after hours	$414.43	$421.35	$429.83	$436.83
Change time switch	$214.92	$219.91	$224.75	$228.89
Change tariff	$222.08	$227.24	$232.24	$236.51
Reprogram card meters	$1,289.52	$1,319.45	$1,348.51	$1,373.31
Install metering related load control	$286.56	$293.21	$299.67	$305.18
Removal of load control device	$286.56	$293.21	$299.67	$305.18
Change load control relay channel	$143.28	$146.61	$149.83	$152.59
Services provided in relation to a Retailer of Last Resort (ROLR) event	$2,807.65	$2,875.22	$2,943.87	$3,007.81
Non-standard network data requests	$697.86	$714.80	$731.64	$746.34
Provision of services for approved unmetered supplies	$101.75	$104.11	$106.46	$108.62
Customer requested appointments	$742.27	$764.34	$782.23	$797.92
Removal/rearrangement of network assets	$305,207.01	$312,269.99	$319,536.09	$325,919.67
Aerial markers	$722.09	$742.06	$758.69	$772.98
Tiger tails	$2,438.50	$2,495.88	$2,551.87	$2,600.00
Assessment of parallel generator applications	$1,744.65	$1,787.00	$1,829.11	$1,865.84
Witness testing	$3,849.24	$3,939.48	$4,027.65	$4,103.74
Removal/rearrangement of public lighting assets	$20,791.76	$21,287.48	$21,775.02	$22,198.63

3 Default Metering Services

Table 19: Indicative annual metering services charges

Metering service type	Cost recovery type	2016-17 Fixed charge ($/p.a.) GST Exclusive	2017-18 Fixed charge ($/p.a.) GST Exclusive	2018-19 Fixed charge ($/p.a.) GST Exclusive	2019-20 Fixed charge ($/p.a.) GST Exclusive
Primary	Non–capital	$42.03	$41.35	$40.69	$40.04
	Capital	$10.23	$11.54	$13.01	$14.67
Controlled load	Non–capital	$15.45	$15.21	$14.96	$14.72
	Capital	$3.76	$4.24	$4.78	$5.39
Embedded generation	Non–capital	$10.45	$10.28	$10.12	$9.96
	Capital	$2.55	$2.87	$3.24	$3.65

Table 20: Indicative call out fees for final meter reads

Call out fee - Final meter reads	2016-17 Fixed charge ($/call out) GST Exclusive	2017-18 Fixed charge ($/call out) GST Exclusive	2018-19 Fixed charge ($/call out) GST Exclusive	2019-20 Fixed charge ($/call out) GST Exclusive
Call out fee - Final meter read - Urban/short rural feeder	$53.54	$55.21	$57.02	$58.98
Call out fee - Final meter read - Long rural feeder	$214.16	$220.85	$228.09	$235.92

4 Public Lighting Services

Table 21: Indicative daily public lighting charges

Public Lighting Services	2016-17 Fixed charge ($/day/light) GST Exclusive	2017-18 Fixed charge ($/day/light) GST Exclusive	2018-19 Fixed charge ($/day/light) GST Exclusive	2019-20 Fixed charge ($/day/light) GST Exclusive
EO&O - Major	$1.0896	$1.1674	$1.2506	$1.3398
EO&O - Minor	$0.6492	$0.6955	$0.7451	$0.7983
G&EO - Major	$0.4400	$0.4714	$0.5050	$0.5411
G&EO - Minor	$0.2882	$0.3088	$0.3308	$0.3544

Table 22: Indicative public lighting exit fees

Public lighting exit fee	2016-17 Fixed charge ($/light) GST Exclusive	2017-18 Fixed charge ($/light) GST Exclusive	2018-19 Fixed charge ($/light) GST Exclusive	2019-20 Fixed charge ($/light) GST Exclusive
EO&O - Major - Exit fee	$1,438	$1,474	$1,511	$1,548
EO&O - Minor - Exit fee	$869	$891	$913	$936
G&EO - Major - Exit fee	$238	$244	$250	$256
G&EO - Minor - Exit fee	$202	$207	$212	$217

Appendix C Avoidable and stand-alone costs for Standard Control Services

This appendix sets out Ergon Energy's approach to the development of avoidable costs, expected revenue and stand-alone costs for our Standard Control Services (SCS) for the 2016-17 to 2019-20 period and presents estimates for each year based on the tariff classes detailed in our TSS and currently available information.

1 Stand-alone costs

Ergon Energy estimates the stand-alone costs for each tariff class by calculating the total annual costs of operating the network, less the cost of serving all other tariff classes. This approach uses the revenue cap as a first step, which is allocated to tariffs using the Distribution Cost of Supply (DCOS) Model. The network is assumed to remain in its current state with supply voltages unchanged. Individual classes of assets and their associated costs are 'optimised' by removing a portion, while still notionally providing the necessary capacity to supply just the tariff grouping concerned.

Our assessment of stand-alone costs is determined from a review of the network in response to the following question:

If only one tariff grouping XX is supplied, what assets would be required to supply only this tariff grouping? If only these assets are required, what revenue should be collected?

The estimated stand-alone costs for groupings of similar SCS tariff classes (e.g. high voltage connected customers) are, in effect, the portion of the revenue cap that could be avoided if all other tariff groupings were not served.

2 Avoidable costs

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

If XX tariff class was not connected to the network, what assets would not be required? If these assets are not required, what revenue should not be collected?

Again, the network is assumed to remain in its current state with supply voltages unchanged. Individual classes of assets and their associated costs from the DCOS Model are 'optimised' by removing a portion, as the demand is notionally reduced for each tariff grouping not supplied, while still maintaining the same standard of network service to be maintained to all remaining tariff groupings.

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

3 Comparison of avoidable costs, expected revenue and stand-alone costs

In line with previous years, Ergon Energy has determined the proportion of our regulated revenue to be recovered from each tariff class using the below method.

Ergon Energy allocates the revenue cap to tariff classes on the basis of:

- the number of customers connected to the network. This allocator is appropriate for those costs that are dependent upon or driven by the number of connected customers. Ergon Energy has a number of costs that are customer number based, including a significant proportion of the overhead costs of the business that are driven by the number of staff and systems required to serve the customer base.
- any time energy. This is used to allocate those costs that are related to the size of the customer but not specifically to the demand that customer places on the network (e.g. network operating costs). In addition, consistent with the recovery mechanisms used in the electricity market, costs that cannot be directly related to a product or service are recovered through the use of any time energy prices (e.g. some overhead costs).
- Any Time Maximum Demand. This method of allocation is used for shared system costs, on the basis that network development is driven by peak demand.
- asset value. This is used to apportion return on assets, depreciation and operating expenditure costs.

The following tables demonstrate our compliance with the avoidable and stand-alone costs obligation for the 2017 to 2020 period. As noted above, these estimates are based on currently available information and are subject to change in the relevant pricing year.

Table 23: 2016-17 avoidable costs, expected revenue and stand-alone costs for SCS (GST Exclusive)

Tariff class	Avoidable costs	Expected revenue	Stand-alone costs	Clause 6.18.5(a) met
Individually Calculated Customer – East	$20,636,857	$39,702,415	$268,299,927	Yes
Individually Calculated Customer – West	$2,067,118	$13,822,956	$31,498,641	Yes
Individually Calculated Customer – Mount Isa	$0	$0	$0	Yes
Connection Asset Customer – East	$27,783,088	$81,335,795	$291,042,860	Yes
Connection Asset Customer – West	$359,222	$10,985,883	$29,676,859	Yes
Connection Asset Customer – Mount Isa	$0	$0	$0	Yes
Standard Asset Customer – Large – East	$198,030,754	$316,055,456	$1,058,484,792	Yes

Tariff class	Avoidable costs	Expected revenue	Stand-alone costs	Clause 6.18.5(a) met
Standard Asset Customer – Large – West	$53,287,853	$86,055,625	$290,455,047	Yes
Standard Asset Customer – Large – Mount Isa	$3,972,076	$4,558,554	$14,400,336	Yes
Standard Asset Customer – Small – East	$334,682,048	$677,514,001	$1,058,484,792	Yes
Standard Asset Customer – Small – West	$110,216,876	$197,865,198	$290,455,047	Yes
Standard Asset Customer – Small – Mount Isa	$6,618,200	$10,680,168	$14,400,336	Yes
Standard Asset Customer – Unmetered – East	$7,463,065	$18,395,701	$615,072,259	Yes
Standard Asset Customer – Unmetered – West	$2,047,913	$2,681,502	$29,440,517	Yes
Standard Asset Customer – Unmetered – Mount Isa	$102,158	$312,679	$776,728	Yes

Table 24: 2017-18 avoidable costs, expected revenue and stand-alone costs for SCS (GST Exclusive)

Tariff class	Avoidable costs	Expected revenue	Stand-alone costs	Clause 6.18.5(a) met
Individually Calculated Customer – East	$19,156,275	$36,902,815	$248,991,729	Yes
Individually Calculated Customer – West	$1,872,647	$12,823,963	$28,554,472	Yes
Individually Calculated Customer – Mount Isa	$0	$0	$0	Yes
Connection Asset Customer – East	$25,789,802	$75,438,508	$270,188,778	Yes
Connection Asset Customer – West	$325,427	$10,852,333	$26,889,429	Yes
Connection Asset Customer – Mount Isa	$0	$0	$0	Yes
Standard Asset Customer – Large – East	$183,823,121	$290,358,587	$982,544,246	Yes
Standard Asset Customer – Large – West	$48,717,599	$79,984,792	$263,129,540	Yes
Standard Asset Customer – Large – Mount Isa	$3,729,027	$4,241,260	$13,328,248	Yes
Standard Asset Customer – Small – East	$310,670,425	$630,030,791	$982,544,246	Yes
Standard Asset Customer – Small – West	$99,404,889	$175,896,889	$263,129,540	Yes
Standard Asset Customer – Small – Mount Isa	$6,072,815	$9,876,238	$13,328,248	Yes
Standard Asset Customer – Unmetered – East	$6,927,630	$18,985,074	$570,944,159	Yes
Standard Asset Customer – Unmetered – West	$1,855,249	$2,550,344	$26,670,805	Yes

Appendix C: Avoidable and stand-alone costs for Standard Control Services

Tariff class	Avoidable costs	Expected revenue	Stand-alone costs	Clause 6.18.5(a) met
Standard Asset Customer – Unmetered – Mount Isa	$94,552	$276,119	$718,902	Yes

Table 25: 2018-19 avoidable costs, expected revenue and stand-alone costs for SCS (GST Exclusive)

Tariff class	Avoidable costs	Expected revenue	Stand-alone costs	Clause 6.18.5(a) met
Individually Calculated Customer – East	$19,477,769	$37,499,996	$253,140,563	Yes
Individually Calculated Customer – West	$1,890,262	$13,035,515	$28,842,137	Yes
Individually Calculated Customer – Mount Isa	$0	$0	$0	Yes
Connection Asset Customer – East	$26,222,625	$76,042,090	$274,627,907	Yes
Connection Asset Customer – West	$328,488	$11,024,923	$27,146,858	Yes
Connection Asset Customer – Mount Isa	$0	$0	$0	Yes
Standard Asset Customer – Large – East	$186,908,174	$294,292,171	$999,034,016	Yes
Standard Asset Customer – Large – West	$49,616,189	$81,327,220	$265,604,670	Yes
Standard Asset Customer – Large – Mount Isa	$3,810,429	$4,321,753	$13,429,832	Yes
Standard Asset Customer – Small – East	$315,884,322	$641,881,901	$999,034,016	Yes
Standard Asset Customer – Small – West	$99,899,614	$176,742,163	$265,604,670	Yes
Standard Asset Customer – Small – Mount Isa	$6,066,120	$9,897,770	$13,429,832	Yes
Standard Asset Customer – Unmetered – East	$7,043,895	$19,651,620	$580,526,158	Yes
Standard Asset Customer – Unmetered – West	$1,872,700	$2,630,513	$26,921,684	Yes
Standard Asset Customer – Unmetered – Mount Isa	$95,273	$283,799	$724,381	Yes

Table 26: 2019-20 avoidable costs, expected revenue and stand-alone costs for SCS (GST Exclusive)

Tariff class	Avoidable costs	Expected revenue	Stand-alone costs	Clause 6.18.5(a) met
Individually Calculated Customer – East	$19,595,088	$37,652,356	$254,635,317	Yes
Individually Calculated Customer – West	$1,888,552	$13,089,488	$28,834,822	Yes
Individually Calculated Customer – Mount Isa	$0	$0	$0	Yes
Connection Asset Customer – East	$26,380,571	$76,037,880	$276,186,529	Yes
Connection Asset Customer – West	$328,191	$11,069,733	$27,126,723	Yes
Connection Asset Customer – Mount Isa	$0	$0	$0	Yes
Standard Asset Customer – Large – East	$188,033,968	$294,690,018	$1,005,051,445	Yes
Standard Asset Customer – Large – West	$50,004,568	$81,711,786	$265,364,385	Yes
Standard Asset Customer – Large – Mount Isa	$3,856,021	$4,353,890	$13,404,548	Yes
Standard Asset Customer – Small – East	$317,786,971	$647,100,245	$1,005,051,445	Yes
Standard Asset Customer – Small – West	$99,375,972	$175,946,830	$265,364,385	Yes
Standard Asset Customer – Small – Mount Isa	$6,001,933	$9,836,671	$13,404,548	Yes
Standard Asset Customer – Unmetered – East	$7,086,322	$20,333,450	$584,022,811	Yes
Standard Asset Customer – Unmetered – West	$1,871,006	$2,683,670	$26,897,329	Yes
Standard Asset Customer – Unmetered – Mount Isa	$95,093	$285,455	$723,017	Yes

Appendix D Assignment and reassignment to Standard Control Services tariff classes and tariffs

This appendix sets out Ergon Energy's procedures on assigning and reassigning customers to SCS tariff classes and tariffs. The procedures describe the requirements which retailers and/or customers must comply with when requesting a tariff class or tariff assignment or reassignment and how Ergon Energy will respond to such requests.

The procedures are consistent with Attachment 14 of the Distribution Determination, where applicable.

1 Assignment and reassignment of customers to tariff classes

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

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

In determining the tariff class to which a customer or potential customer will be assigned or reassigned, Ergon Energy will take into account one or more of the following factors:

- the nature and extent of the customer's usage, by examining:
    - historical consumption data
    - expected annual consumption for new customers or those customers who have a written agreement to change their supply capacity
- the nature of the customer's connection to the network, by considering:
    - the customer's geographical location (e.g. East, West or Mount Isa)
    - assets utilised in connecting to the network[40]
- whether remotely-read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.

We will also ensure that:

- customers with similar connection and usage profiles are treated equally
- customers who have micro-generation facilities are treated no less favourably than customers with similar load profiles without such facilities. We will achieve this by charging customers with micro-generation facilities the same network tariff for supply to their connection point as any other customer with a similar load profile.

[40] This may require interrogation of various internal systems to obtain information on site-specific connection asset arrangements.

The criteria we use to assess which tariff class we should assign or reassign a customer or potential customer to is set out in Table 27.

It is important to note that Ergon Energy does not reassign customers without careful review and justification.

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

Table 27: Tariff class assignment and reassignment criteria for SCS

Network user group	Typical characteristics of customers assigned	Criteria for reassigning customers to a different tariff class
Standard Asset Customers (SACs)	▪ Annual consumption is expected to be below 4 GWh p.a.	Reassigned to a different network user group: ▪ Annual consumption increases, or is expected to increase, above 4 GWh p.a., and/or ▪ A customer requests an increase in supply capacity requiring augmentation to connection assets which results in a dedicated supply system which is quite different and separate from the remainder of the supply network. Reassigned within the SAC network user group: ▪ Annual consumption of a SAC Small customer increases to over 100 MWh p.a. ▪ Annual consumption of a SAC Large customer decreases to less than 100 MWh p.a.
Connection Asset Customers (CACs)	▪ Required capacity above 1,500 kVA, or ▪ Annual consumption is expected to exceed 4 GWh p.a.	Reassigned to ICCs: ▪ Annual consumption increases, or is expected to increase, above 40 GWh p.a., and/or ▪ A customer requests an increase in supply capacity requiring augmentation to their connection assets which results in a dedicated supply system which is quite different and separate from the remainder of the supply network. Reassigned to SACs: ▪ Annual consumption reduces or is expected to reduce below 4 GWh p.a. and their dedicated supply system is not considered to be quite different and separate from the remainder of the supply network, and/or ▪ Required capacity falls below 1,500 kVA.[41]

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

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

1.1 Notification of a tariff class assignment and reassignment

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

- advice that the retailer may request further information from Ergon Energy and that they may object to the proposed assignment or reassignment
- a link to Ergon Energy's website where a copy of the internal procedures for reviewing objections is located
- advice that resolution is available via the Queensland Energy and Water Ombudsman for small customers[42] (to the extent resolution of such disputes are within their jurisdiction), if the objection is not resolved by Ergon Energy to the satisfaction of the customer or the customer's retailer
- otherwise advice that resolution is available via the dispute resolution process under Part 10 of the National Electricity Law (the Law), if the objection is not resolved by Ergon Energy (under our internal review system) or the Queensland Energy and Water Ombudsman to the satisfaction of the customer or the customer's retailer.

Subject to any appeal, the effective date will depend on the reason for assignment or reassignment, whether the meter is required to be reprogrammed or replaced to give effect to the change, and the meter type as outlined in the table below:

Reason for assignment or reassignment	Effective date
New connection	• The date the premises is energised by Ergon Energy (i.e. the NMI status is changed to 'Active' in the market systems)
Ergon Energy initiated based on change in connection or load characteristics (e.g. NMI reclassification, annual usage review)	• Type 5-6 meter - the date of the *next* scheduled (actual) meter read • Type 1-4 meter – the date of the *next* billing period This provides opportunity for the retailer or customer to object to the proposed reassignment and request a review of the decision before the change takes effect[43].
Other change initiated by the customer or retailer which triggers a tariff class reassignment (e.g. application for increased/decrease capacity, request to change network tariff of an existing or	Where no new meter or meter reprogramming is not required: • Type 5-6 meter - the date of the *last* (actual) meter read • Type 1-4 meter – the date of the *last* billing period

[42] SAC Small.
[43] See Clause 10 of the National Energy Retail Rules

Reason for assignment or reassignment	Effective date
move-in customer)	Where a new meter or meter reprogramming is required: • The date the meter is installed or reprogrammed

It is important to note that a tariff class reassignment may necessitate a change to a customer's network tariff assigned to a NMI. Details of Ergon Energy's proposed new Network Tariff Code(s) will be included in the written notification mentioned above. Subject to any appeal, the new Network Tariff Code will also take effect from the date indicated above.

1.2 Objections to a tariff class assignment or reassignment

If a retailer raises an objection to a tariff class assignment or reassignment for SCS, Ergon Energy will make every effort to investigate and address the retailer's concerns when the retailer first contacts Ergon Energy.

In the first instance, the retailer should contact the email address specified on the proposed assignment or reassignment email sent by Ergon Energy to the retailer. Ergon Energy will endeavour to inform the retailer of the outcome of our review, including a reason for our decision within five business days of receiving such a request.

If the retailer is not satisfied with the outcome of this review, the objection can be escalated to the Manager responsible for network pricing. The retailer can request an objection to be escalated by contacting Network Pricing via email (netprice@ergon.com.au). The Manager will advise the retailer of the outcome of an escalated objection as soon as practical.

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

- the Queensland Energy and Water Ombudsman (small customers only)
- the AER for resolution via the dispute resolution process available under Part 10 of the Law.

If the retailer's objection to a tariff class assignment or reassignment is upheld by Ergon Energy (via our internal review process) or the appropriate external body, then an adjustment will be made to tariffs as part of the next network bill.

1.3 Customer or retailer-initiated reassignments

Ergon Energy will generally only action a retailer or customer request to reassign an existing customer to another tariff class, if the retailer or customer has also applied for a change to the network tariff assigned to a NMI (via the process outlined in Section 2.2 below). Where necessary, Ergon Energy will then update the applicable tariff class.

2 Assignment and reassignment of customers to tariffs

2.1 Tariff assignment

Tariff assignment occurs when a customer lodges an application to connect to our network at a new connection point (i.e. new connection).

In order to determine the tariff assignment, we examine information collected from the customer/retailer/contractor with respect to the expected usage at the premises, load capacity, the location of the premises and the type of customer (e.g. business or residential).

Where multiple tariffs are relevant to a particular customer,[44] Ergon Energy will apply the default tariff applicable at the time of their application, unless otherwise advised by the retailer. This retailer advice should be provided in the "Proposed tariff" field of the B2B Service Order Request, or in the event that this field has not been filled in, by using the Average Daily Load (kWh) information provided on the B2B Service Order Request.

The examples below illustrate how Ergon Energy determines the appropriate tariff to be assigned to a customer.

Example 1 – Residential customer

Assumptions:

- *Estimated annual consumption: 4 MWh*
- *Location of premises: Townsville*
- *Customer classification: Residential*
- *Transmission Network Connection Point (TNCP): Townsville East*

Assessment:

The customer would be assigned to the:

- *SAC network user group and further into the SAC Small customer group, as the customer's estimated annual consumption is less than 100 MWh*
- *East Zone, as the customer's premises is located in Townsville*
- *default primary network tariff for the SAC Small customer group, which is the IBT. Further, as the customer classification is 'Residential', the customer would be assigned to the 'IBT Residential' network tariff*
- *TUOS Region 2, since the customer is connected to the Townsville East TNCP.*

Result:

- *The customer's Network Tariff Code would be ERIBT2.*

[44] For example, residential and small to medium business customers who use less than 100 MWh of electricity per year can access the Inclining Block Tariff, Seasonal Time-of-Use Energy tariff or the Seasonal Time-of-Use Demand tariff.

Example 2 – Business customer

Assumptions:

- *Estimated annual consumption: 20 GWh*
- *Location of premises: Longreach*
- *Connected at: 22 kV Bus*
- *TNCP: Lilyvale 66 kV*

Assessment:

The customer would be assigned to the:

- *CAC network user group, as the customer's estimated annual consumption is greater than 4 GWh but less than 40 GWh*
- *West Zone, as the customer's premises is located in Longreach*
- *default CAC 22/11 kV Bus network tariff, as the customer is connected at 22/11 kV Bus*
- *TUOS Region 1, since the customer is connected to the Lilyvale 66 kV TNCP.*

Result:

- *The customer's Network Tariff Code would be WC22BT1.*

As the initial tariff assignment will be based on prospective information obtained from the customer or their representative, it is the responsibility of the customer or their representative to monitor the suitability of the tariff applied and advise Ergon Energy if a tariff reassignment is required.

2.2 Tariff reassignment

Ergon Energy-initiated

Tariff reassignments initiated by Ergon Energy typically occur when a customer alters the underlying characteristics of their connection; in terms of size or nature of usage (i.e. there is a change to their tariff class). Therefore, the tariff change is consequential to a tariff class change and the tariff class reassignment notification process described above applies.

The new network tariff assigned to the NMI will take effect from the date of the *next* scheduled (actual) meter read. For customers with a Type 1-4 meter which are read remotely, the change will apply from the *next* billing period. Network charges under the existing network tariff will continue to be billed by Ergon Energy until the effective date.

Customer or retailer-initiated

Customers or retailers may also apply to Ergon Energy for a change to the network tariff assigned to a NMI by completing the 'Application for Review Form' available on Ergon Energy's website at: www.ergon.com.au/networktariffs. The completed form must be submitted to the email address specified on the form.

Customer or retailer-initiated tariff reassignments can be requested for a variety of reasons. For example where the customer wishes to 'opt-in' to a different tariff (instead of the default tariff applied to the premises) or where there has been a takeover of an existing connection (change in tenancy).As above, Ergon Energy takes into account a range of information in determining whether a tariff reassignment should occur. Following this assessment, Ergon Energy will inform the customer and/or retailer within five business days of receiving such a request of the decision taken. If Ergon Energy disagrees that the network tariff proposed by the customer or retailer is applicable to the NMI, the notification will include a reason for the rejection.

A change to the network tariff may necessitate a change to the tariff class assigned to a NMI. In this instance, the notification to the retailer will be provided in accordance with Section 1.3 of this appendix.

As noted in Section 1.3, any new network tariff (and tariff class) assigned to the NMI will take effect from:

Where no new meter or meter reprogramming is not required:

- Type 5-6 meter - the date of the *last* (actual) meter read at the premises
- Type 1-4 meter – the date of the *last* billing period applicable to the premises

Where a new meter or meter reprogramming is required:

- The date the meter is installed or reprogrammed

For completeness it is noted that where a change to a network tariff(and tariff class) require a NMI reclassification, as stated in section 1.3 above, any new network tariff (and tariff class) will take effect from:

- Type 5-6 meter - the date of the next scheduled (actual) meter read
- Type 1-4 meter – the date of the next billing period

Network charges under the existing network tariff will continue to be billed by Ergon Energy until the effective date. Backdating of charges prior to the effective date will not be allowed by Ergon Energy.

Subject to a change in usage or the pattern of usage at the customer's installation, a further request to change the network tariff (and Network Tariff Code) assigned to a NMI should not be made until a period of 12 months has elapsed from the previously approved request for the NMI.

Appeals process

A customer and/or retailer may appeal:

- a tariff reassignment initiated by Ergon Energy
- our decision to reject the network tariff proposed by the customer or retailer.

The appeals process to follow is outlined in Table 28 below.

Table 28: Network tariff appeals process

Scenario	Appeals process
The customer and/or retailer do not agree with a tariff reassignment initiated by Ergon Energy.	The email sent to the retailer outlining the proposed tariff reassignment will provide the appropriate contact details. The request should be sent by the customer's retailer. .
The customer and/or retailer do not agree with Ergon Energy's decision to maintain the current network tariff.	The email sent to the retailer rejecting the proposed tariff reassignment will provide the appropriate contact details. The request should be sent by the customer's retailer.
The customer does not agree to a network tariff change initiated by their retailer.	The customer should contact their retailer in the first instance. Following this, if the matter is not resolved to the satisfaction of the customer, the customer may complete an 'Application For Review Form', which is available at www.ergon.com.au/networktariffs. The completed form must be submitted to the email address specified on the form. .

Ergon Energy will review the appeal and the customer's eligibility for the proposed network tariff. We will notify the customer and/or retailer of the outcome of the appeals review as soon as practical.

Appendix E Assignment and reassignment to Alternative Control Services tariff classes and tariffs

This appendix sets out Ergon Energy's procedures on assigning and reassigning customers to ACS tariff classes and tariffs. The procedures are consistent with Attachment 14 of the Distribution Determination, where applicable.

1 Assignment and reassignment of customers to tariff classes

1.1 Assignment

Assignment to Ergon Energy's ACS tariff classes occurs as a result of:

- major customers requesting a new connection to the network or an upgrade to their existing connection
- real estate developers requesting a new connection to the network
- public lighting customers requesting installation of a new public light, or gifting a new public light to Ergon Energy
- small customers requesting the installation and provision of a Type 5 or 6 meter, or a change to their existing metering arrangements (e.g. installing controlled load or solar)
- new service orders or work requests being raised as a result of a request for service by either a customer and/or retailer.

Customers and/or retailers essentially assign themselves to an ACS tariff class when requesting the service they require. For example, a retailer requesting a de-energisation for a particular customer's premises (after hours) would be assigned to the quoted services tariff class as this service is a quoted service.

1.2 Reassignment

Ergon Energy generally does not initiate tariff class reassignments for our ACS.

We note there are some circumstances where a field crew attends a site and the scope of work does not match the service order or work request. This may mean a different service type and/or tariff class may be more appropriate. In these instances, the job is generally returned as not completed and a new service order or work request would need to be submitted. Consequently, a new tariff class assignment, rather than reassignment, would occur.

Retailers may initiate a tariff class reassignment by contacting Network Pricing via email (netprice@ergon.com.au). Any change in the assigned tariff class will only proceed upon approval by Ergon Energy. Ergon Energy will make our determination having regard to the type of service being requested by the customer and/or retailer, the Distribution Determination and any applicable law.

1.3 Notification of a tariff class assignment and reassignment

Consistent with the Distribution Determination, Ergon Energy does not provide written notification to the retailer of the tariff class to which a customer has been assigned or reassigned.

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

1.4 Objections to a tariff class assignment or reassignment

If a retailer raises an objection to an ACS tariff class assignment or a decision by Ergon Energy to reject a customer or retailer-initiated ACS tariff class reassignment, Ergon Energy will make every effort to investigate and address the retailer's concerns when the retailer first contacts Ergon Energy.

In the first instance, the retailer should contact Network Pricing via email requesting a review of the tariff class assignment or our reassignment decision. Ergon Energy will endeavour to inform the retailer of the outcome of our review, including a reason for our decision within five business days of receiving such a request.

If the retailer is not satisfied with the outcome of this review, the objection can be escalated to the Manager responsible for network pricing. The retailer can request an objection to be escalated by contacting Network Pricing via email. The Manager will advise the retailer of the outcome of an escalated objection as soon as practical.

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

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

If the retailer's objection to a tariff class assignment is upheld by Ergon Energy (via our internal review process) or the appropriate external body, then any adjustment which needs to be made to tariffs will be made as part of the next network bill.

2 Assignment and reassignment of customers to tariffs

2.1 Tariff assignment

Customers and/or retailers essentially assign themselves to an ACS tariff(s) when requesting the service they require. We therefore rely on information provided by the customer and/or retailer to determine the appropriate tariff(s) (e.g. information submitted on a Form A or business-to-business (B2B) service order request).[45]

2.2 Tariff reassignment

Ergon Energy generally does not initiate tariff reassignments for our ACS.

As noted above, there may be some circumstances where a field crew attends a site and the scope of work does not match the service order or work request. In these instances, the job is generally returned as not completed and a new service order or work request would need to be submitted. Consequently, a new tariff assignment, rather than reassignment, would occur.

Customers/retailers may initiate a tariff reassignment by contacting Network Pricing. Any change in the assigned tariff will only proceed upon approval by Ergon Energy. Ergon Energy will make our determination having regard to the type of service being requested by the customer and/or

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[45] In order to implement the new charging structures for Default Metering Services and Public Lighting Services from 1 July 2015, Ergon Energy was required to carry out initial tariff assignments for our existing customers/connections (i.e. those customers who connected before 1 July 2015). These assignments were based on information available in our systems (as at 1 July 2015) and were consistent with the application of charges set out in the Distribution Determination.

retailer, the Distribution Determination and any applicable law.

2.3 Appeals process

If a retailer raises an objection to an ACS tariff assignment or a decision by Ergon Energy to reject a customer or retailer-initiated ACS tariff reassignment, Ergon Energy will make every effort to investigate and address the retailer's concerns when the retailer first contacts Ergon Energy.

In the first instance, the retailer should contact Network Pricing via email requesting a review of the tariff assignment or our reassignment decision. Ergon Energy will endeavour to inform the retailer of the outcome of our review, including a reason for our decision within five business days of receiving such a request.

If the retailer is not satisfied with the outcome of this review, the objection can be escalated to the Manager responsible for network pricing. The retailer can request an objection to be escalated by contacting Network Pricing via email. The Manager will advise the retailer of the outcome of an escalated objection as soon as practical.

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