Energex

Annual Pricing Proposal

Distribution Services for 1 July 2018 to 30 June 2019

energex

positive energy

Version control

Version	Date	Description
v.1	31 March 2018	Initial Pricing Proposal submitted to the AER for approval.

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

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

1 Introduction

1.1 Background

On 30 June 2016, Energex Limited (Energex) became a subsidiary of Energy Queensland Limited which is the holding company for both Energex and Ergon Energy Corporation Limited (Ergon Energy). Energex is the Distribution Network Service Provider (DNSP) that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. We provide distribution services to 1.4 million domestic and business connections, delivering electricity to a population base of around 3.4 million people.

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

1.2 Purpose

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

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

1.3 Classification of services

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

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

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

[1] The National Electricity Rules, Version 106.

Alternative Control Services are comprised of:

- Fee based services – one-off distribution services that we undertake at the request of an identifiable customer, retailer or appropriate third party which are levied as a separate charge, in addition to our Standard Control Services. These services are priced on a 'fixed fee' basis as the costs of providing the service (and therefore price) can be assessed in advance of the service being requested.

  Examples of fee based services include temporary connections, de energisations, re-energisations and supply abolishment.

- Quoted services – similar to fee based services, but they are 'priced on application' as the nature and scope of these services are variable and the costs (and therefore price) are specific to the individual requestor's needs (e.g. design and construction of connection assets for major customers, real estate development connections and special meter reads etc.).

- Default Metering Services – relate to:
  - Type 6 meter installation and provision (before 1 July 2015)
  - Type 6 meter installation and provision (on or after 1 July 2015 and up until 30 November 2017), where the replacement meter was initiated by Energex as a DNSP
  - Type 6 metering maintenance, reading and data services.

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

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

- Public Lighting Services – relate to the provision, construction and maintenance of public lighting assets owned by Energex, and emerging public lighting technology. We recover the costs of providing Public Lighting Services through a daily public lighting charge billed to retailers. We may also charge a one-off exit fee as a Quoted Service[2], when a customer requests the replacement of an existing public light for a light emitting diode (LED) luminaire before the end of its useful life.[3]

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

1.4 Regulatory framework

As a DNSP, Energex is subject to economic regulation by the AER under the *National Electricity Law* (the Law) and the NER. Under the Law and the NER, the AER is responsible

[2] Public light exit fee is derived in accordance with Quoted Services formula outline in Equation 4-2 in Section 4.3.2 of this Pricing Proposal.

[3] Outside of our LED transition program.

for regulating the revenues we can earn, and the prices we can charge our customers for the provision of network services.

1.4.1 Distribution determination

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

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

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

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

1.4.2 Tariff structure statement

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

As part of this new framework, we developed and submitted to the AER for approval a Tariff Structure Statement (TSS) for the 2017 to 2020 period.[4] The AER approved Energex's TSS on 28 February 2017.[5]

The TSS sets out our proposed tariff classes, tariffs and tariff structures that will apply over the regulatory control period, and demonstrates compliance with the new pricing principles set out in Chapter 6 of the NER (see Section 1.4.3 below). The TSS interfaces with Energex's Pricing Proposal, and each Pricing Proposal must be consistent with the approved

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

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

TSS. This Pricing Proposal is the second Pricing Proposal developed in accordance with the 2017-20 TSS.

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

1.4.3 Pricing objective and principles

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

- each tariff is set based on the Long Run Marginal Cost (LRMC) of providing the network service to the customers assigned to that tariff (clause 6.18.5(f))
- tariffs are set in such a manner that minimises distortions to the price signal resulting from complying with the LRMC pricing principle and the efficient usage decisions of consumers (clause 6.18.5(g)(3))
- the revenue expected to be recovered from each tariff reflects Energex's total efficient costs (clause 6.18.5(g)(10))
- we have considered the impact on customers of changes to tariffs between regulatory years, and we have adjusted prices to the extent necessary to meet the customer impact principles and ensure a smooth transition to cost reflectivity (clause 6.18.5(h))
- tariff structures are set in a manner that can be understood by customers (clause 6.18.5(i))
- tariffs comply with the NER and all applicable regulatory instruments (clause 6.18.5(j)).

The expected revenue recovered from our tariffs must also:

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

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

1.4.4 Queensland Government cap on fee based services

The Queensland Government has historically set maximum price caps to apply to a subset of Energex's Alternative Control Services through Schedule 8 of the *Electricity Regulation 2006*. Since the price caps are imposed through legislation, they take precedence over the Alternative Control Services prices approved by the AER.

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

1.5 Summary of changes

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

Table 1-1 Standard Control Services tariff changes

Tariff class	Proposed tariff changes
SAC	The introduction of an optional cost reflective time-of-use demand based tariff for large LV customers with a consumption greater than 100 MWh per year (NTC7200 – LV Demand). This new tariff is part of the implementation of Energex's tariff reform set out in the TSS. Further information is provided in our TSS and the rates applicable for 2018-19 are provided in Attachment 1.
SAC	To inform the development of our forthcoming 2020-25 TSS, we propose to introduce a new cost reflective network tariff, NTC6400-Residential Lifestyle, that is to be offered to retail customers subject to the limitations of the threshold tariff provisions set out in clause 6.18.1C of the NER. This innovative tariff is a departure from conventional demand-based tariffs currently offered in the NEM. This small scale tariff offering will enable us and retailers to market test the tariff during the current 2017-20 TSS period. The rates applicable for 2018-19 for the tariff are provided in Attachment 1.

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

1.6 Structure of this document

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

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

Table 1-2 Pricing Proposal structure

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

We have also provided a number of models and supporting attachments to the AER as part of this Pricing Proposal. Where possible, these documents will be made publicly available. The documents subject to confidentiality requirements are listed in Appendix 7 of this Pricing Proposal.

1.7 Alignment of pricing proposals

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

1.8 Supporting network pricing documents

In addition to this Pricing Proposal, we have developed and published a number of related network pricing documents to assist network users, retailers and interested parties understand the development and application of tariffs and connection charges.[6] These documents are outlined in Figure 1-1 below.

[6] Link to the pricing page on the Energex website: https://www.energex.com.au/home/our-services/pricing-And-tariffs.

Figure 1-1 Supporting network pricing documentation

Tariff Structure Statement	• Sets out the proposed tariff classes, tariffs and tariff structures for the 2017-20 period. • Details how the proposed tariff classes, tariffs and tariff structures comply with the pricing principles. • Describes the tariff setting process for Starndard Control Services and Alternative Control Services. • Provides details on Energex's tariff assignment policy. • Provides indicative prices for the 2017-20 period for Standard Control Services and Alternative Control Services. • Approved by the AER in February 2017, following stakeholder consultation.
Pricing Proposal	• Provides how Energex's tariff classes, tariffs and tariff structures for Standard Control Services and Alternative Control Services in compliance with the requirements set out in Chapter 6 of the NER, the AER's Distribution Determination, and our TSS. •Provides indicative prices for 2019-20 •Submitted to the AER annually
2018-19 Network Tariff Tables	•Provides Energex's 2018-19 prices for our Standard Control Services and Alternative Control Services developed in accordance with the requirements set out in the NER, the AER's Distribution Determination and our TSS •Submitted to the AER as part of the Pricing Proposal. •Referred to as Attachment 1 in this Pricing Proposal.
Network Tariff Guide	• An operational document for customers, retailers, and consultants, setting out the Network Tariff Codes, product codes, Ellipse Codes adn Peace charge codes for Direct Control Services. • Provides a list of services which are requested through B2B communciation channels. • Published annually, and updated as required.
Information Guide for Standard Control Services Pricing	• Provide additional information for customers detailing how Energex's revenue cap is recovered from various customer groups through network trariffs. • Published annually and updated as required.
Connection Policy	• Sets out when a connection charge may be payable by retail customers or real estate developers and the aspects of the connection service for which a charge may be applied. • Details how Energex calculates the capital contributions to be paid. • Approved by the AER in 2015 as part of the Distribution Determination.

2 Tariff classes and tariffs for Standard Control Services

Rule Requirement

Clause 6.18.2 Pricing Proposals

(b) A pricing proposal must:

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

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

Clause 6.18.3 Tariff classes

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

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

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

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

(2) the need to avoid unnecessary transaction costs.

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

2.1 Tariff classes

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

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

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

Our pricing methodologies are developed according to the principle that network tariffs are an equitable reflection of the network user's utilisation of the existing network, while minimising the inefficiency of price averaging. This approach helps ensure customers with broadly similar characteristics, who impose similar costs on the network, are classed together so that they face similar tariff structures.

Consistent with our TSS, Energex will apply three tariff classes for Standard Control Services in 2018-19 mainly based on the voltage level at which customers are connected to the network. These tariff classes are listed in Table 2-1 below.

Table 2-1 Tariff classes for 2018-19

Tariff class	Eligible customers
Individually Calculated Customers (ICC)	Customers are assigned to the ICC tariff class if they are coupled to the network at 110 kV or 33 kV. Customers with a network coupling point at 11 kV may also be assigned to the ICC tariff class if: • the customer's electricity consumption is greater than 40 GWh per year at a single connection; and/or • the customer's demand is greater than or equal to 10 MVA; and/or • the customer's circumstances mean that the average shared network charge becomes meaningless or distorted. ICC tariffs are based on: • the actual dedicated connection assets utilised by the customer; plus • the customer's specifically identified portion of the shared distribution network utilised for the electricity supply, including common and non-system assets.
Connection Asset Customers (CAC) [a]	Customers with a network coupling point at 11 kV who are not assigned to the ICC tariff class are allocated to the CAC tariff class. CAC tariffs are based on: • the actual dedicated connection assets utilised by the customer; plus • average charges for use of the shared distribution network, including common and non-system assets.
Standard Asset Customers (SAC)	All customers connected at LV are classified as SACs. SAC tariffs are based on: • average charges for dedicated connection assets; plus • average charges for use of the shared distribution network, including common and non-system assets.

Note:

a. In circumstances where a customer's connection point does not have the appropriate metering to access tariffs within the tariff class to which they are assigned, the customer may be temporarily assigned to a tariff within the SAC tariff class.

Consistent with clause 6.18.3(b) of the NER, all of our customers receiving Standard Control Services are a member of one or more tariff classes set out in Table 2-1. It should be noted that, in accordance with clause 6.18.4(a)(3), we do not make reference to customer's export load in assigning customers to tariff classes.

2.2 Tariffs and tariff structures

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

Tariffs have three key defining characteristics:

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

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

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

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

Charge	Charging parameter	Application to tariffs
Fixed charge	Represented as a rate ($) per day or rate ($) per day per device.	Applies to all primary tariffs.
Usage (volume) charge	Represented as a rate ($) per kWh. Different parameters apply to this charge for different tariffs. Within a tariff structure, volume charge rates can be flat or be applied to different blocks (based on consumption) or times (peak and off-peak).	Applies to all primary tariffs.[a]
Demand charge	Represented as either a rate ($) per kW or a rate ($) per kVA. Different parameters and charge rates apply to this depending on the tariff, namely: • a single maximum in the billing	Applies to all primary tariffs except NTC8400 (Residential flat), NTC8900 (Residential Time-of-Use), NTC8500 (Business Flat), and NTC8800 (Business Time-of-

Charge	Charging parameter	Application to tariffs
	period • a single maximum within a peak demand window during the billing period.	Use).
Capacity charge	Represented as a rate ($) per kVA	NTC1000 (ICC)
Excess demand charge	Represented as a rate ($) per excess kVA. It is measured as a single maximum demand outside the peak charging window minus the maximum demand during the peak period in the billing period.	NTC7400 (Demand Time-of-Use 11kV), NTC7200 (LV Demand Time-of-Use)[b]
Network access allowance	Represented as a rate ($) per month. Monthly charge based on the customer's nominated access band.	NTC6400 (Residential Lifestyle Tariff)
Summer peak top-up	Represented as a rate ($) per kWh consumed above the customer's nominated access band within a month during the summer peak window.	NTC6400 (Residential Lifestyle Tariff)

Note:

a. EGs are not charged for the electricity exported into the distribution network.
b. Offered from 1 July 2018.

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

2.3 Tariff assignment policies

Rule Requirement

Clause 6.18.1A Tariff structure statement

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

Distribution Determination requirement

Attachment 14 – D.3 Procedures for assigning and reassigning retail customers to tariff classes.

To meet the requirements of clause 6.18.1A(a)(2) of the NER and the general procedures set out in Attachment 14 of the Distribution Determination, we have developed detailed procedures for the assignment and reassignment of customers to Standard Control Services tariff classes and tariffs. Consistent with the NER requirements, these policies and procedures are contained in our TSS (Refer to Chapter 5 of the TSS). We will comply with these procedures in 2018-19.

In addition, the Attachment 14 of the Distribution Determination requires Energex's Pricing Proposal to set out a method of how we will review and assess the basis on which a customer is charged, where the charging parameters for a particular tariff result in a basis of charge that varies according to the customer's usage or load profile.[7] Our compliance with this requirement for Standard Control Service tariff classes and tariffs is set out below and also in our TSS.

Review of the charging basis

We periodically review the assignment of customers to tariff classes and tariffs to ensure customers are assigned to the correct tariff class and tariff. For large customers connected at the 11kV network and above, demand and volume characteristics are reviewed annually, while connection assets and network configurations are reviewed periodically or on request.

The decision making for tariff class and tariff re-assignment is similar to that used for the assignment of customers to tariff classes and tariffs set out in the TSS. Indeed, consistent with clause 6.18.4 of the NER, we ensure customers with similar characteristics are treated equitably by specifically taking into account the nature and extent of their usage and the nature of their connection to the network. Energex's detailed procedures for the re-assignment of customers to tariff classes and tariffs can be found in Section 5.3 and Appendix 3 of the TSS.

For customers with demand levels that fluctuate frequently, we may apply a reasonable tolerance limit on tariff thresholds to mitigate frequent tariff re-assignment, and subsequently limit customer impact.

Finally, it should be noted that customers requesting a tariff re-assignment are allowed only one tariff change per 12 month period.[8] This ensures transaction costs are contained and pricing signals are not distorted by constant changes.

[7] AER, Final Decision Energex determination 2015-16 to 2019-20, Attachment 14 – Control mechanisms, October 2015, page 28.

[8] Such a tariff change is free of charge to customers.

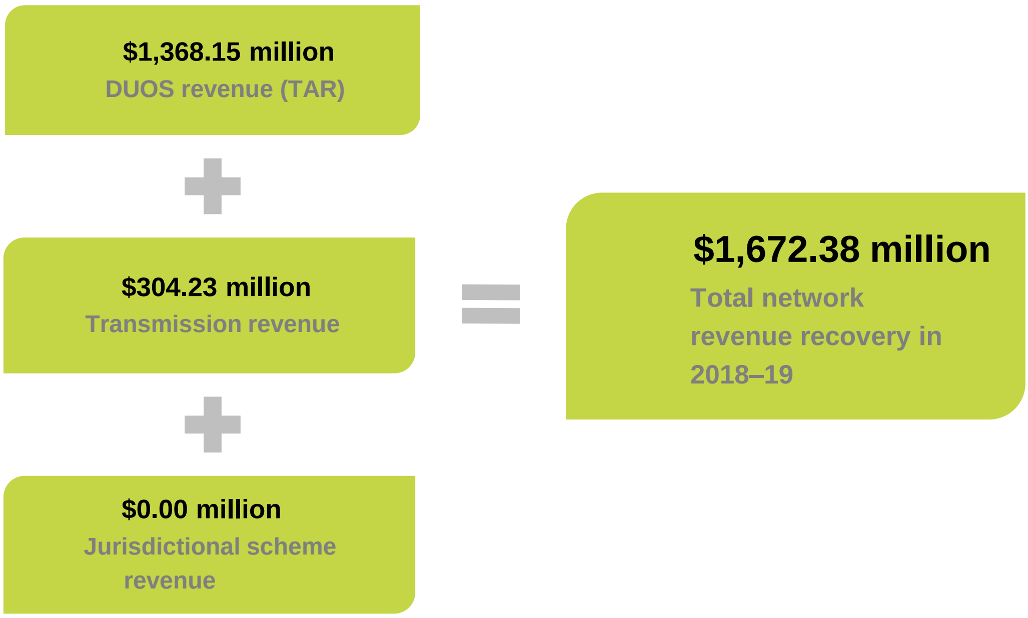
3 Tariff levels for Standard Control Services

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

3.1 Total Revenue Requirement for 2018-19

In 2018-19, the total revenue that we will need to recover from network users (via our network tariffs) is approximately $1,672.38 million as shown in Figure 3-1. Detailed calculations are provided in Table 3-1.

Figure 3-1 Summary total network revenue for 2018-19



The amount to be recovered includes Energex's Total Annual Revenue (TAR), transmission costs[9] and jurisdictional scheme amounts (set to nil until at least 2020).

The TAR, which reflects Energex's smoothed expected revenue plus other annual adjustments, will be approximately $1,368.15 million in 2018-19. This is 7.0 per cent below what Energex expects to recover from network users in 2017-18.

When calculating the smoothed expected revenue for 2018-19, we applied the revenue cap formulae set out by the AER in its Distribution Determination.

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

3.2 Distribution Use of System (DUOS) charges

3.2.1 Control mechanism

Distribution Determination Requirement

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

Total Annual Revenue (TAR)

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

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

Figure 3-2 Revenue cap formulae

1. $TAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$ i=1,…, n and j=1,…,m and t=1,…,5
2. $TAR_t = AR_t \pm I_t \pm B_t \pm C_t$ t=1,…,5
3. $AR_t = AR_{t-1}(1+\Delta CPI_t)(1-X_t)(1+S_t)$

Where:

TAR_t is the total annual revenue in 2018-19.

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

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

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

AR_{t-1} is the annual smoothed expected revenue for 2017-18.

I_t is the final carryover amount from the application of the DMIS from the 2010-15 distribution determination.[10]

B_t is the sum of:

- Any under or over recoveries relating to capital contributions 2013-14 and 2014-15.[11]
- Any under or over recovery of actual revenue collected through DUOS charges in regulatory year t-2 (i.e. 2016-17) as calculated using the method in Appendix A of Attachment 4 of the Distribution Determination.

C_t is the sum of adjustments related to:

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

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

- The feed-in tariff (FiT) pass-through amounts relating to the 2014-15 regulatory year[12]
- Any AER approved pass through amounts during the 2015-20 regulatory control period.

ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics (ABS) Consumer Price Index (CPI) All groups, Weighted Average of Eight Capital Cities, from the December quarter in regulatory year t-2 to the December quarter in regulatory year t-1:

> 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 regulatory year 2018-19, t-2 corresponds to December 2016 and t-1 corresponds to December 2017

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

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

In addition to the TAR, transmission charges[13] and jurisdictional scheme amounts (including FiT payments made under the Solar Bonus Scheme (SBS) and the AEMC levy)[14] are also recovered from customers.

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

Table 3-1 2018-19 Total Revenue calculations

Component	Amount ($m)	Comments/reference
(a) Annual Revenue (AR_{t-1})	**$1,463.47**	2017-18 annual smoothed expected revenue as per the amount in the approved 2017-18 Pricing Proposal.
(b) Consumer Price Index (CPI_t)	1.91%	Annual percentage change in the CPI All Groups, Average of Eight Capital Cities from the December quarter in 2016 to the December quarter in 2017 as published on the Australian Bureau of Statistics (ABS) website.

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

13 Transmission network charge are also known as DPPC or, previously, known as Transmission Use of System (TUOS) charges.

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

(c) X Factor (X_t)	5.26%	X factor for 2018-19 updated as a result of the annual return on debt update, as determined by the AER.
(d) STPIS (S_t)	0.06%	S-factor determined in accordance with the STPIS requirements. It is based on Energex's annual performance for 2016-17 against STPIS which resulted in an S-factor of 2% .
Impact on Revenue	***-$49.71***	Impact = (a)x(1+(b))(1-(c))(1+(d))-(a)
Annual Smoothed Expected Revenue 2018-19 (AR_t)	**$1,413.76**	
Adjustments:		
DMIS carryover amount (I_t)	N/A	No longer applicable.
DUOS over recoveries (B_t)	-$45.61	Over recovery for 2016-17. Further information is provided in Table 3-2.
Capital contributions under recoveries (B_t)	N/A	No longer applicable.
Solar Bonus Scheme (SBS) FiT payment pass-through (C_t)	N/A	No longer applicable.
Total Annual Revenue (TAR)	**$1,368.15**	
Further adjustments:		
Jurisdictional Schemes	Nil	Queensland SBS Jurisdictional Scheme for and AEMC levy amounts. On 31 May 2017 Energex received a direction from the Queensland Government not to pass on the jurisdictional scheme charges to customers in our network tariffs until at least 2020.
DPPC (or TUOS)	$304.23	Transmission cost to be recovered in 2018-19.
Total Revenue Requirement	**$1,672.38**	Total revenue that Energex will need to recover in 2018-19.
Note: Due to rounding, individual components may not sum to the total.		

DUOS unders and overs account

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

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

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

- maintain a DUOS unders and overs account in our annual pricing proposal
- provide entries in the DUOS unders and overs account for the most recently completed regulatory year (t-2) and the next regulatory year (t). For this Pricing Proposal, year t-2 is 2016-17 and year t is 2018-19.[15]

The AER also requires that Energex's DUOS amounts for the most recently completed regulatory year (t-2) (i.e. 2016-17) be audited. We believe this requirement is met as the information provided is based on the information lodged (and audited) as part of the Annual Reporting Regulatory Information Notice (RIN). It should be noted that the amounts for the next regulatory year (t) are forecast amounts.

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

Table 3-2 DUOS unders and overs account ($'000)

Unders/overs account element	2016-17 Year t-2 (actual)	2018-19 Year t (forecast)
Revenue from DUOS charges	1,542,856	1,368,148
(A) Revenue from DUOS charges	1,542,856	1,368,148
(B) Less Total Annual Revenue for the relevant year	1,502,296	1,368,148
+ Annual revenues (AR)(inclusive of STPIS)	1,248,224	1,413,757
+ Demand Management Incentive Scheme carryover amount	-5,238	
+ Sum of under/over recoveries (Bt) =	39,758	-45,609
+ Capital contributions	17,403	
+ DUOS revenue under/over recovery approved	22,355	
+ Sum of pass through adjustments (Ct) =	219,552	
+ Feed-in tariff cost pass throughs	219,552	
+ Approved pass through amounts		

15 AER, Final Decision Energex determination 2015-16 to 2019-20, Attachment 14 – Control Mechanisms, October 2015, page 17.

(A minus B) Under/over recovery of revenue for regulatory year	**40,560**	**0**
DUOS Unders and Overs Account		
Nominal WACC t-2 (per cent)	6.04%	
Nominal WACC t-1 (per cent)	6.04%	
Opening balance	0	45,609
Under/over recovery of revenue for regulatory year	40,560	-45,609
Interest on under/over recovery for 2 regulatory years	5,049	N/A
Closing balance	**45,609**	**0**
Note: Due to rounding, individual components may not sum to total.		

3.2.2 Revenue allocation

Rule Requirement

Clause 6.18.1A Tariff structure statement

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

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

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

3.2.3 Recovery of DUOS charges from generators

Rule Requirement

Clause 6.1.4 Prohibition of DUOS charges for the export of energy

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

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

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

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

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

3.2.4 Forecast weighted average revenue

Rule Requirement

Clause 6.18.2 Pricing Proposals

(b) A pricing proposal must:

(4) set out, for each tariff class related to standard control services, the expected weighted average revenue for the relevant regulatory year and also for the current regulatory year.

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

Table 3-3 Expected weighted average DUOS revenue by tariff class

Tariff class	2017-18 ($m)	2018-19 ($m)	Change in weighted average revenue
ICC	$38.1	$34.8	-8.73%
CAC	$122.0	$117.5	-3.62%
SAC	$1,315.6	$1,215.8	-7.59%
Total	**$1,475.7**	**$1,368.1**	**-7.29%**

Note:
All amounts are GST exclusive.

3.2.5 Side constraints

Rule requirement

Clause 6.18.6 Side constraints on tariffs for standard control services

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

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

Distribution Determination Requirement

Attachment 14 - Energex's revenue from each tariff class must be consistent with the side constraint formula in Figure 14.2.

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

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

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

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

Equation 3-1 Side constraint formula

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

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

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

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

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

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

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

minus one.

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

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

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

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

- any under or over-recoveries relating to capital contributions from 2013–14 and 2014–15
- any under or over recovery of actual revenue collected through DUOS charges in regulatory year t–2 as calculated using the method in Appendix A of Attachment 14 of the AER's Distribution Determination. This revenue adjustment is no longer applicable in 2018-19.

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

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

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

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

Component	Values
ΔCPI_t	1.91%
X_t	5.26%
S_t	0.06%
$I_t^{'}$	0.00%
$B_t^{'}$	-3.09%
$C_t^{'}$	0.00%
Permissible percentage	**0.92%**

Table 3-5 below confirms that Energex's expected weighted average revenue to be raised from each tariff class in 2018-19 is below the percentage allowed by the side constraint formula (i.e. the permissible percentage threshold of 0.92 per cent).

Table 3-5 Compliance with side constraint formula

Tariff class	Calculated percentage change between 2017-18 and 2018-19	Permissible percentage change
ICC	-8.73%	0.92%
CAC	-3.62%	0.92%
SAC	-7.59%	0.92%

3.2.6 Avoidable and stand-alone costs

Rule Requirement

Clause 6.18.5 Pricing Principles

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

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

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

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

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

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

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

Details of our approach to determining the avoidable and stand-alone costs for our Standard Control Services are provided in Chapter 2 of our TSS.

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

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

Tariff class	Avoidable cost ($)	2018-19 Revenue ($)	Stand-alone costs ($)	Clause 6.18.5(e) compliance
ICC	$11,264,512	$34,804,268	$46,722,071	Yes
CAC	$14,565,946	$117,545,133	$155,166,879	Yes
SAC	$61,544,911	$1,215,798,884	$1,253,589,209	Yes
Note: All amounts are GST exclusive.				

3.2.7 Long run marginal cost

Rule Requirement

Clause 6.18.5 Pricing Principles

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

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

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

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

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

It should be noted that neither the calculation of LRMC nor the application of LRMC to tariff-setting are prescribed in the NER and, therefore, can be undertaken in a number of different ways. Chapter 2 of our TSS and chapter 6 of the TSS’s Explanatory Notes set out the methodology we have adopted to calculate LRMC and our approach to incorporating these values in our tariff structures and rates.

Application of LRMC in tariff setting

In our tariff-setting for 2018-19 we have applied the approach to LRMC detailed in our TSS. This approach includes:

- **Selection of appropriate charging parameter:** The LRMC values have been incorporated in the demand charge parameter of the demand based tariffs as it is considered the most suitable mechanism to signal the cost of future network augmentation. For the tariffs without a demand charge parameter, LRMC has been allocated to the peak usage charge of time-of-use usage tariffs and the flat usage charge of the anytime usage tariffs. For the proposed Lifestyle Tariff, LRMC is incorporated in both the capacity band and peak summer top-up charging parameters. It should be noted, however, for the first band of the Lifestyle tariff (network use allowance of 0 kWh per month), LRMC is fully allocated to the top-up charge.
- **Strength of the LRMC signal:**
  - For our ‘legacy tariffs’: These tariffs and associated tariff structures have been in place for many years and, therefore, do not reflect the LRMC signal in its pure form. Recognising the impact on customers, legacy tariffs are being gradually restructured to better reflect more efficient network usage signals than they previously did.

- Cost reflective tariffs: For all tariff classes except ICC, we have introduced alternative optional time-of-use demand tariffs that customers can adopt through their choice of retail tariff. The recently introduced cost reflective tariffs (i.e. Residential Demand (NTC7000), LV Business Demand (NTC7100), LV Demand Time-of-Use (NTC7200), and Demand Time-of-Use 11kV (NTC7400)), place a higher and more appropriate weight on signalling the LRMC of using the distribution network at peak times.

Table 3-7 provides the LRMC values for each voltage level for 2018-19. These figures are based on those included in the TSS, escalated using CPI.

Table 3-7 Undiversified LRMC values by voltage levels for 2018-19

Voltage Level	$/kVA/month	$/kW/month	c/kWh peak energy	c/kWh energy
110/33 kV	$5.041			
11 kV Bus	$7.690			
11 kV Line	$10.338			
LV Business		$10.860	$2.691	$1.281
LV Residential		$10.860	$10.763	$1.281
Note: All amounts are GST exclusive.				

3.2.8 Least distortionary recovery of residual costs

Rule Requirement

Clause 6.18.5 Pricing Principles

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

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

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

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

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

In establishing the 2018-19 network tariffs, we confirm that it has been necessary to allocate residual costs in order to recover the portion of the revenue cap that that could not be fully recovered through the LRMC-based charging parameters. This means that:

- For our LRMC-based tariffs: we have to recover the revenue shortfall through the fixed and usage charges. For these tariffs, the demand charge parameter is solely used to signal the efficient usage of the network.
- For legacy tariffs: some residual revenues are recovered from the same tariff charge parameter that signals LRMC. In 2018-19 we will continue to transition the legacy tariffs so that the charging parameters conveying the price signal get closer to the LRMC based value while managing customer impact.

Our TSS and accompanying Explanatory Notes further discuss how our tariff structures ensure we recover our revenue allowance in the least distortionary way, consistent with clause 6.18.5(g) of the NER.

3.2.9 Tariff simplicity

Rule Requirement

Clause 6.18.5 Pricing Principles

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

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

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

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

3.3 Designated Pricing Proposal (or TUOS) Charges

Rule Requirement

Clause 6.18.7 Recovery of designated pricing proposal charges

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

Clause 6.18.2 Pricing proposals

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

3.3.1 Background

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

- the use of Powerlink's transmission network to deliver high voltage electricity from generators to Energex's distribution network
- avoided transmission (TUOS) charges paid to eligible EGs
- payments made to other DNSPs for the supply of distribution services.

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

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

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

3.3.2 Transmission costs

3.3.2.1 Designated pricing proposal charges paid to TNSPs (Powerlink)

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

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

Energex is also currently charged by Powerlink for the entry and exit of services provided at the 110kV network from Rocklea to Archerfield. Clause 11.39.7 of the NER provided that Energex could recover these costs as DPPC up until 30 June 2015.

The AER has advised Energex that these charges can continue to be recovered as DPPC from 1 July 2015, on the basis that when the transitional arrangement under clause 11.39.7 of the NER expired, the charges became a prescribed service from that time and therefore qualified as DPPC.

3.3.2.2 Payment to other DNSPs

In contingency circumstances, Essential Energy (the DNSP in northern New South Wales) provides supply from its Terranora Substation to Energex's Kirra Zone Substation. Under this arrangement, Essential Energy requires Energex to pay for the use of its assets.

The charges established by Essential Energy in respect of this arrangement are based on approved rates for each month in which the alternate supply is utilised. These costs have been incorporated into the costs for the Mudgeeraba TNCP and are consequently passed through to users. The amount to Essential Energy paid in 2018-19 is included in Table 3-9.

3.3.2.3 Avoided TUOS charges

Rule Requirement

Clause 5.5 Access arrangements relating to Distribution Networks

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

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

- (1) determine the charges for the locational component of prescribed TUOS services that would have been payable by the Distribution Network Service Provider for the relevant financial year:
  - (i) where the Connection Applicant is an Embedded Generator, if that Embedded Generator had not injected any energy at its connection point during that financial year;
  - (ii) where the Connection Applicant is a Market Network Service Provider, if the Market Network Service Provider had not been connected to the Distribution Network Service Provider's distribution network during that financial year; and
- (2) determine the amount by which the charges calculated in subparagraph (1) exceed the amount for the locational component of prescribed TUOS services actually payable by the Distribution Network Service Provider, which amount will be the relevant amount for the purposes of paragraph (h).

Where we are liable to pay an Avoided TUOS payment to an EG in accordance with clause 5.5(h) and (i) of the NER, the payment amount is recovered as part of the DPPC charges passed through to all customers. This allocation is premised on the fact that avoided TUOS do not solely impact on the transmission connection point to which the EG is connected but also benefit all customers.

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

(a) Determine the charges for the locational component of prescribed DPPC services that would have been payable by Energex had the EG not injected any energy at its connection point during that financial year.
(b) Determine the amount by which the charges calculated in (a) exceeds the amount for the locational component of prescribed DPPC services actually payable by Energex.
(c) Credit the value from (b) to the EG account.

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

The estimated total amount in avoided TUOS liability to EGs accrued in 2018-19 is included in Table 3-9 below.

3.3.3 Recovery of DPPC (revenue)

Where administratively efficient, the forecast DPPC will be passed on to customers in the same form of price structure as it is received.

For ICCs, our network tariffs preserve the economic signals present in the structure of the DPPC as the charges are based on the relevant transmission connection point. This provides the greatest cost-reflectivity for these customers and is a feasible method for calculating charges since the number of such customers is relatively small.

DPPC charges for CAC tariffs are based on average DPPC charges. This provides a significant degree of cost-reflectivity for this group of customers while recognising the practical difficulties of calculating individual charges for each customer connected at the 11 kV network.

DPPC cost amounts are allocated to SAC tariffs proportionally based on a mixture of average monthly maximum demands and volumes, and recovered from the same tariff structure as DUOS charges (fixed charge, maximum demand and/or volume charge).

It should be noted for the recently introduced cost reflective demand tariffs (NTC7400 - Demand Time-of-Use 11kV, NTC7200 - Demand Time-of-Use LV, NTC7100 – Business Demand, NTC7000 – Residential Demand) Energex will not recover DPPC from the fixed charge parameter, but rather from the demand charging parameter to strengthen the network LRMC signal.

The network charging parameters applied to each tariff for the recovery of DPPC are detailed in Table 3-8 below.

Table 3-8 DPPC recovery from tariff charging parameters

Tariff class	Tariff	Network Tariff Code (NTC)	Tariff charging parameters							
			Daily supply charge ($/day)	Daily supply charge ($/day/ $M-CAV)	Daily supply charge ($/day/ $M-NCCAV)	Monthly maximum demand charge ($/kVA/ month)	Monthly maximum demand charge ($/kW/month)	Excess demand ($/kVA/ month)	Usage charge flat (c/kWh)	Time-of-use usage charge (c/kWh)
ICC	ICC	1000	✓			✓[a]				✓[b]
CAC	EG 11 kV	3000[c]	✓			✓				✓
	11 kV Line	4500	✓			✓				✓
	11 kV Bus	4000	✓			✓				✓
	HV Demand	8000[c]	✓			✓				✓
	Demand Time-of- Use 11kV	7400[d]				✓		✓	✓	
SAC	Demand Large	8100	✓			✓			✓	
	Demand Small	8300	✓			✓			✓	
	Business Flat	8500	✓						✓	
	Business Time-of-Use	8800	✓							✓

Tariff class	Tariff	Network Tariff Code	Tariff charging parameters							
	Demand Time-of-Use LV	7200[e]								
	Business Demand	7100[f]					✓		✓	
	Residential Flat	8400	✓						✓	
	Residential Time-of-Use	8900	✓							✓
	Residential Demand	7000[f]					✓		✓	
	Solar FiT	9900		N/A						
	Super Economy	9000							✓	
	Economy	9100							✓	
	Smart Control	7300[f]							✓	
	Unmetered	9600							✓	

Notes:

a. Monthly maximum demand charge for ICCs is the locational charge as published by Powerlink and consists of the nominated demand plus average demand multiplied by rate.
b. Usage (volume) charge for ICCs is a combination of general and common charge as published by Powerlink.
c. These tariffs will no longer be offered to new customers from 1 July 2015.
d. Cost reflective tariff offered from 1 July 2017.
e. Cost reflective tariff offered from 1 July 2018.
f. Cost reflective tariff offered since 1 July 2016.

3.3.4 DPPC unders and overs accounts

Rule requirement

Clause 6.18.7 Recovery of designated pricing proposal charges

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

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

(1) subject to subparagraphs (2) and (3) below, is consistent with the method determined by the AER in the relevant distribution determination for the Distribution Network Service Provider;

(2) ensures a Distribution Network Service Provider is able to recover from retail customers no more and no less than the designated pricing proposal charges it incurs; and

(3) adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year.

Distribution Determination Requirement

Attachment 14 - Energex must submit as part of its annual pricing proposal, a record of the amount of revenue recovered from DPPC and associated payments in accordance with Appendix B of this attachment.

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

The unders and overs account in Table 3-9 below sets out Energex's over recovery based on information lodged and audited in our 2016-17 RIN.

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

Table 3-9 DPPC unders and overs account

Unders/overs account element	2016-17 actual ($'000)	2018-19 forecast ($'000)
(A) Revenue from DPPC charges	495,856	304,235
(B) Less DPPC related payments for regulatory year =	482,976	304,235
DPPC charges to be paid to TNSP	483,915	317,783
Avoided TUoS payments	354	547
Inter-distributor payments (Payments to Essential	357	388

Energy for the supply from its Terranora Substation to Energex's Kirra Zone Substation)		
DPPC revenue under/over recovery approved	-1,651	-14,484
(A minus B)Under/over recovery for regulatory year	**12,880**	**0**
Unders and Overs Account		
Nominal WACC t-2 (per cent)	6.04%	N/A
Nominal WACC t-1 (per cent)	6.04%	N/A
Opening balance	0	14,484
Under/over recovery of revenue for regulatory year	12,880	-14,484
Interest on under/over recovery for 2 regulatory years	1,604	N/A
Closing balance	**14,484**	**0**
Note: Due to rounding, individual components may not sum to total.		

3.4 Jurisdictional schemes

Rule Requirement

Clause 6.18.2(b) Pricing proposals

A pricing proposal must:

(6A) set out how jurisdictional scheme amounts for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those amounts;

(6B) describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria.

Clause 6.18.7A Recovery of jurisdictional scheme amounts

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

In accordance with clause 6.18.2(b)(6A) of the NER, our pricing proposal must set out how jurisdictional scheme amounts for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from the over or under recovery of those amounts.

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

- the Solar Bonus Scheme which obligates Energex to make FiT payments for energy supplied into our distribution network from specific micro-embedded generators[16]

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

- the energy industry levy covering a proportion of the Queensland Government's funding commitments for the AEMC which, under our Distribution Authority we are obligated to pay since 2016.

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

3.4.1 Jurisdictional scheme payments unders and overs account

Rule Requirement

Clause 6.18.7A Recovery of jurisdictional scheme amounts

Pricing Proposal

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

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

(1) subject to subparagraphs (2) and (3) below, is consistent with the method determined by the AER for jurisdictional scheme amounts in the relevant distribution determination for the Distribution Network Service Provider, or where no such method has been determined, with the method determined by the AER in the relevant distribution determination in respect of designated pricing proposal charges;

(2) ensures a Distribution Network Service Provider is able to recover from customers no more and no less than the jurisdictional scheme amounts it incurs; and

(3) adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year.

Distribution Determination Requirement

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

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

The unders and overs account presented in Table 3-10 below is based on information lodged (and audited) in our 2016-17 RIN.

Table 3-10 Jurisdictional scheme amounts unders and overs account

Unders/overs account element	2016-17 actual ($'000)	2018-19 forecast ($'000)
(A) Revenue from jurisdictional schemes	186,800	0
(B) Less jurisdictional scheme payments for regulatory year =	177,478	
+ SBS FiT payments	177,320	
+ AEMC Levy payments	158	
+ Jurisdictional scheme amounts revenue under/over recovery approved		
(A minus B)(Under)/over recovery for regulatory year	**9,322**	
Jurisdictional scheme amount unders and overs account		
Nominal WACC t-2 (per cent)	6.04%	N/A
Nominal WACC t-1 (per cent)	6.04%	N/A
Opening balance	0	10,482
(Under)/over recovery of revenue for regulatory year	9,322	-10,482
Interest on under/over recovery for 2 regulatory years	1,160	N/A
Closing balance	**10,482**	**0**
Note: Due to rounding, individual components may not sum to total.		

3.4.2 Forecast of jurisdictional scheme amounts

The estimated jurisdictional scheme amount in 2018-19 is $146.98 million. It comprises an estimated $157.3 million in SBS FiT payments, $10.48 million in over recovery from 2016-17 and $0.16 million in AEMC levy. As demonstrated in Table 3-11 below, this amount will not be passed on to customers through network charges, but will instead be covered by a proportion of the Queensland Government’s grant.

Table 3-11 Forecast for 2018-19 SBS FiT payments

SBS FiT payment calculation	2018-19
Solar FiT Payment ($M)	**$157.30**
Over recovery[a]	(10.48)
Total Solar Fit Payment ($M)	**$146.82**
AEMC Levy	$0.16
Total Jurisdictional Scheme amount	**$146.98**
Portion of the Qld Government grant	**$146.98**
Balance	**$0**
Note: a. Refer to Table 3-2 for further details.	

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

3.5 Demand, energy and customer number forecasts

Rule Requirement

Clause 6.18.8(a)(3) Approval of pricing proposal

The AER must approve a pricing proposal if the AER is satisfied that, among other things, all forecasts associated with the proposal are reasonable.

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

It should be noted that, in Energex's 2015-20 Regulatory Proposal and TSS, we provided the AER with details on the key drivers underpinning our demand and energy forecasts, and expected customer numbers throughout the 2015-20 regulatory control period.[17,18]

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

17 Energex's Regulatory Proposal June 2015 to June 2020, November 2014.

18 Energex's Explanatory Notes accompanying the 2017-20 Tariff Structure Statement, Section 4.3.

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

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

The forecast demand, energy and customer numbers for 2018-19 are included in Table 3-12 below.

Table 3-12 2018-19 demand, energy and customer number forecasts

Tariff class	ICC	CAC	SAC	Total
Average Demand (MVA)	398,723	805,641	1,615,177	**2,819,542**
Undiversified Average Maximum Demand (MW)	363,590	753,825	8,808,000	**9,925,415**
Volume (GWh)	1,945.7	3,777.4	15,485.0	**21,208.1**
Customer numbers	57	583	1,464,219	**1,464,859**

Notes:
- Undiversified demand assumes all customers are utilising the network at the same time.
- Maximum demand (MW) used to allocate costs to tariffs.
- Demand in MW for small non-demand customers was derived from the volumes to which a specific load factor was applied.

3.6 2018-19 Standard Control Services charges

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

Section 5.4.1 provides further explanation on the differences between our proposed 2018-19 tariffs and the corresponding indicative pricing levels developed as part of the 2017-18 annual pricing proposal process and included in the 2017-18 Indicative Pricing Schedule.

4 Alternative control services

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

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

4.1 Alternative Control Services tariff classes

Rule Requirement

Clause 6.18.3 Tariff classes

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

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

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

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

(2) the need to avoid unnecessary transaction costs.

As indicated in Section 2.1, all of Energex’s customers for Direct Control Services are a member of one or more tariff classes (thus meeting clause 6.18.3(b) of the NER). Being a subset of Direct Control Services, this obligation extends to Alternative Control Services. Further, clause 6.18.3(c) of the NER is met by Energex distinguishing between the tariff classes for Standard Control Services and for Alternative Control Services.

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

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

Table 4-1 Energex's Alternative Control Services tariff classes

Tariff class	Nature of services
Connection Services	Pre connection (other than general connection enquiry service). Connection (other than small customer connections). Post Connection (other than operating and maintaining connection assets). Accreditation/Certification.
Ancillary Network Services	Services provided in relation to the retailer of last resort. Other recoverable works.
Metering Services	Type 6 Metering Services. Auxiliary Metering Services.
Public Lighting Services	Provision, construction and maintenance of public lighting. Other public lighting. Emerging public lighting.

4.2 Tariffs and charging parameters

Rule Requirement

Clause 6.18.2 Pricing proposals

(b) A pricing proposal must:

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

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

In accordance with clause 6.18.2(b)(2) of the NER, our Pricing Proposal sets out the Alternative Control Services which have been specified in our TSS.

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

Energex's tariffs for Alternative Control Services are grouped according to the classification and basis of pricing determined by the AER in its Distribution Determination. This aids in providing tariffs that appropriately reflect the costs incurred in providing the relevant service to the relevant type of customer. At the same time, the tariffs within each tariff class have been grouped together in a manner that is easy for customers and retailers to understand, and which avoids unnecessary transaction costs as a result of tariff proliferation.

Tariff charging parameters

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

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

Service	Charge	Charging parameter	Control mechanism formula
Connection services	Fixed charge	Fixed rate ($) per service. The rate varies depending on the service requested.	Refer section 4.3.1
	Quoted service	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver it.	Refer section 4.3.2
Metering services	Fixed charges	Metering services charge: ($) per day per tariff. Metering service charges differ by: • The type of metering service (primary, controlled load, solar PV); and • The type of cost recovery (capital, non-capital).	Refer section 4.3.1
		Fixed rate ($) per service. The rate varies depending on the service requested.	Refer section 4.3.1
	Quoted service	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver it.	Refer section 4.3.2
Public lighting services	Fixed charges	Fixed rate ($) per day per light.	Refer section 4.3.1
		Fixed rate ($) per service. The rate varies depending on the service requested.	Refer section 4.3.1
	Quoted service	Fixed rate ($) per service. The rate varies depending on the service requested.	Refer section 4.3.2
Ancillary services	Fixed charge	Fixed rate ($) per service. The rate varies depending on the service requested.	Refer section 4.3.1
	Quoted service	Quoted rate ($) per service. The quoted price varies according to the requested service and actual resources required to deliver it.	Refer section 4.3.2

Alternative Control Services tariffs for each tariff class

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

Chapter 6 of our TSS contains a description of the process we undertake each year to establish tariffs for Alternative Control Services. We have applied this approach in establishing the proposed 2018-19 Alternative Control Services tariffs set out in this Pricing Proposal.

4.3 Control mechanism

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

Chapter 6 of our TSS sets out the process and methodology we follow each year to establish our prices for Alternative Control Services, including how we apply the price cap control mechanism formulae set out in the Distribution Determination. The approach to setting tariffs varies for each type of Alternative Control Service:

- For our *fee based services*, we have calculated a cost build-up price in the first year of the regulatory control period which is then adjusted for inflation in subsequent years.
- For our *quoted services*, we have used the quoted services formula to develop illustrative prices. This formula will also be used to develop actual prices for quoted services.
- For our *Default Metering Services* and *Public Lighting Services*, we have applied the relevant price cap formulae specified in the Distribution Determination.

The calculation of our Alternative Control Services is further discussed below.

4.3.1 Control mechanism for fee based services

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

- A schedule of price capped Alternative Control Services for the first year of the 2015-20 regulatory control period based on the cost build-up formula used for quoted services (see Section 4.3.2 below) and using the efficient cost inputs approved by the AER.

- Prices in subsequent years of the regulatory control period 2015-20 are determined using the AER's control mechanism formula in Equation 4-1 and escalated from one year to the next based on changes in the CPI and application of X factors which reflect changes in cost escalators and on-costs.

Equation 4-1 Control mechanism formula for price cap services

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

Where:

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

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

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

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

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

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

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

Service Description	X factor %	Escalation %
Price Cap (fee based services)	(0.76)	2.68
Upfront Meter Capital Charge:		
Single phase one element	(0.46)	2.38
Single phase two elements	(0.46)	2.38
Multi-phase	(0.46)	2.38
Multi-phase with Current Transformer	(0.46)	2.38
Note: Escalation based on $(1+\Delta CPI_t)(1-X_t^i)+A_t^i$ as per the control mechanism formula in Equation 4-1 in this Pricing Proposal where CPI is 1.91% and A_t^i is nil.		

It can be noted that unlike SCS, the WACC is not updated annually to reflect changes in the cost of debt.

19 AER, Final Decision Energex Determination 2015-20 to 2019-20, Attachment 16 – Alternative Control Services, Appendix A, October 2015.

Power of Choice review:

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

4.3.2 Control mechanism for quoted services

Prices for quoted services are determined at the time the customer makes an enquiry. They reflect the individual nature of the service requested and vary based on the resources required to deliver the type of services requested. To develop the prices for quoted services in 2018-19, we apply the AER approved formula outlined in Equation 4-2. This formula includes cost parameters for different services which are representative of the efficient costs of providing and delivering the services.

Equation 4-2 Formula for pricing quoted services

Price = Labour + Contractor Services + Materials + Capital Allowance

where:

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

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

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

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

Cost input changes for quoted services

The Distribution Determination sets out the approved hourly labour rates for 2015-16 to be utilised for the purpose of Equation 4-2. From 2018-19 onwards the base labour rates for 2015-16 will be escalated annually by $(1+\Delta CPI_t)(1-X_t^i)$. For 2018-19 the CPI value is 1.91 per cent and the X-factor is -0.76 per cent, resulting in an escalation rate of 2.68 per cent as shown in Table 4-4.

Table 4-4 2018-19 X factor and escalation for quoted services

Service Description	X factor %	Escalation %
Labour component of quoted services	(0.76)	2.68
Note Escalation based on $(1+\Delta CPI_t)(1-X_t^i)+A_t^i$ as per the control mechanism formula in Equation 4-1 in this Pricing Proposal where CPI is 1.91% and A_t^i is nil.		

Other costs are determined at the time when the quote request is made.

4.3.3 Control mechanisms for Default Metering and Public Lighting Services

For Default Metering and Public Lighting Services (provision, installation and maintenance), a limited building block approach is used to determine the allowable revenues over the regulatory control period, which are then converted in charges that are subject to a price cap. The charges for these services are developed using the control mechanism formula in Equation 4-1 and escalated from one year to the next based on changes in CPI and application of X and A factors (metering service charge).

Table 4-5 2018-19 X factors and escalations for price capped services

Service Description	X factor %	Escalation %
Limited Building Block:		
Public Lighting	(0.98)	2.91
Metering Services Charge		
Non Capital Component	(2.00)	3.95
Capital Component	(1.00)	2.93
Note: Escalation based on $(1+\Delta CPI_t)(1-X_t^i)+A_t^i$ as per the control mechanism formula in Equation 4-1 in this Pricing Proposal where CPI is 1.91% and A_t^i is nil.		

4.4 Tariff assignment policies

As noted in Section 2.3, clause 6.18.1A(a)(2) of the NER requires our TSS to outline the policies and procedures we apply for assigning customers to tariff classes and tariffs.

Prior to the provision of an Alternative Control Service, Energex's customers will be assigned to the relevant tariff class based on the type of Alternative Control Service required. Similar to the tariff class membership requirement for Standard Control Services, Alternative Control Services customers will not receive the service prior to being allocated to the appropriate tariff class.

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

4.5 Compliance with pricing principles

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

4.5.1 Avoidable and stand-alone costs

As noted in Section 3.2.6, clause 6.18.5(e) of the NER requires that for each tariff class, the revenue expected to be recovered should lie on or between an upper bound representing the stand alone cost of serving the customers who belong to that class and a lower bound representing the avoidable cost of not serving those customers.

Our approach to determining the avoidable and stand-alone costs for our Alternative Control Services is set out in Section 6.3.2 of the TSS.

4.5.2 Long run marginal costs and response to price signals

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

Importantly, for Alternative Control Services, each tariff and the movement in tariffs between regulatory years are determined by the AER through the application of caps on the prices of individual services. The AER therefore determines the LRMC of each tariff when it establishes the initial prices and set the inputs, such as the X factors, to be used in the price cap formulae. In establishing these controls, the AER has regard to both the National Electricity Objective and Revenue and Pricing Principles.

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

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

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

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

4.5.3 Recovery of residual costs

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

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

4.6 2018-19 Alternative Control Services charges

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

5 Other Compliance

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

5.1 Customer considerations

5.1.1 Impact on retail customers

Rule Requirement

Clause 6.18.5 Pricing principles

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

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

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

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

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

Standard Control Services

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

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

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

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

- For our legacy tariffs:
  - As noted in Section 3.2.7, progressively incorporating the full LRMC into tariff rates while explicitly limiting adverse customer impacts
  - Applying constraints in tariff setting, such as constraining price impacts for tariff classes and setting maximum limits on the potential individual customer impacts.
- For our 'opt-in' LRMC-based tariffs:
  - Applying the full level of LRMC into tariff levels. This approach is justified given that LRMC-based tariffs are voluntary and customers' ability to remain on legacy tariffs is retained.
  - Applying a Financial Risk Reduction Mechanism for residential customers on tariff NTC7000 – Residential Demand to reduce the risk of experiencing bill shock impact in the first year of adopting the cost reflective LRMC-based tariff (see our TSS and associated Explanatory Notes for further details).
  - Ensuring tariffs are attractive to customers who have the choice to move, or to stay on less efficient default tariffs.

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

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

With ICC and CAC tariffs being confidential, we are not able to include a customer specific impact analysis. However, general trends in ICC and CAC customer impacts between 2017-18 and 2018-19 are presented in Table 5-1. The average impact figures have been calculated based on the revenue we would recover using the 2018-19 approved rates relative to the revenue we would recover using the 2017-18 rates.

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

Tariff Class	Impact	DUOS annual impact (%)	Jurisdictional schemes annual impact (%)	DPPC annual impact (%)	NUOS annual impact (%)
ICC	Average Impact	-8.7%	0%	-8.9%	-8.8%
CAC	Average Impact	-3.6%	0%	-11.9%	-5.9%

In 2018-19, ICC and CAC customers will experience a decrease in their NUOS charges over the previous year with an average reduction of approximately 8.8 per cent for ICC customers and 5.9 per cent for CAC customers.

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

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

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

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

Demand based tariffs	Usage MWh/year	Monthly demand (kVA/month)	2017-18 NUOS ($)	2018-19 NUOS ($)	Annual NUOS increase/ decrease ($)	Annual NUOS increase (%)
Demand Large – NTC8100	1,520	382	$101,901	$94,151	-$7,750	-7.6%
Demand Small – NTC8300	209	60	$17,478	$15,493	-$1,985	-11.4%
Volume based tariffs	**Primary tariff - Usage (MWh/year)**	**Secondary tariff - Usage (MWh/year)**	**2017-18 NUOS ($)**	**2018-19 NUOS ($)**	**Annual NUOS increase/ decrease ($)**	**Annual NUOS increase (%)**
Business Flat – NTC8500	6.4		$899	$814	-$85	-9.4%
Business Time-of-Use – NTC8800	21.6		$2,473	$2,189	-$284	-11.5%
Residential Flat – NTC8400	4.1		$548	$517	-$31	-5.6%
Business Flat – NTC8500 combined with Economy – NTC9100	9.1	1.1	$1,273	$1,143	-$131	-10.3%
Residential Flat – NTC8400 combined with Super Economy – NTC9000	4.2	1.8	$663	$634	-$29	-4.3%
Residential Flat – NTC8400 combined with Economy – NTC9100	3.7	1.8	$650	$611	-$39	-6.0%

Notes:

- Usage scenarios based on actual 2016-17 consumption data.
- Each tariff group contains only NMIs that have data for the full period.
- Customer impact for NTC8900 – Residential Time- of- Use and NTC7300 – Residential Demand is not included as usage scenarios could not be derived due to the very low number of customers on these tariffs.
- NTC9000 and NTC9001 are secondary tariffs, when combined with the primary tariff NTC8400, an overall net benefit to the customer may result.
- For customers with a primary and secondary tariff, consumption scenarios at the secondary tariff are independent from those at the primary tariff. Therefore, any combination of low, typical and high use scenarios between the primary and secondary tariff can be formed. For example a residential customer with a typical usage at the primary tariff may have a low energy usage at the secondary tariff.
- For demand based tariffs, energy and demand levels are independent of each other. Any combination of low, typical and high energy and demand levels can be formed. For example a customer with typical energy usage may have a high demand.
- Solar tariffs NTC7500, NTC9900, NTC9700 and NTC9800 have been excluded from the dataset.

Table 5-1 and Table 5-2 show that customers across the spectrum are expected to experience a decrease in their NUOS charges in 2018-19 compared with their 2017-18 charges. This is largely due to decreases in DUOS resulting from the 2016-17 over-recoveries returned to customers in 2018-19, and a 7.4 per cent decrease in DPPC (TUOS) charges. Further details on these changes between 2017-18 and 2018-19 are provided in Section 5.3.

Alternative Control Services

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

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

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

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

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

Rule Requirement

Clause 6.18.5 Application of the pricing principles

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

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

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

Adjustments to Standard Control Services

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

- The estimated decrease in network charges identified in Table 5-1 and Table 5-2 above have not resulted in the need to vary the tariffs as allowed in clause 6.18.5(h).

- We have, however, set legacy tariffs at variance from the full LRMC for our legacy tariffs to reflect customer impact as permitted in clause 6.18.5(c).

This measure is consistent with our TSS and clause 6.18.5(h) of the NER, and aim to smooth our transition to more cost reflective tariffs.

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

Finally, clause 6.18.5(j) of the NER requires tariffs to comply with the Rules and all applicable regulatory instruments. We confirm that our 2018-19 network tariffs have been developed to be compliant with the NER and the AER's Distribution Determination. We have demonstrated this through our approved TSS, this Pricing Proposal and associated attachments. A summary of our compliance with these obligations is set out in Appendix 4 of this Pricing Proposal.

Adjustments to Alternative Control Services

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

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

5.2 Adjustments to tariffs within a regulatory year

Rule Requirement

Clause 6.18.2 Pricing proposals

(b) A pricing proposal must:

(5) set out the nature of any variation or adjustment to the tariff that could occur during the course of the regulatory year and the basis on which it could occur.

5.2.1 Adjustments to Standard Control Services tariffs within 2018-19

Variations or adjustments to our network tariffs may occur where an ICC or CAC customer advises us that they intend to alter their demand or connection characteristics during the course of the year. In these circumstances, we will recalculate the customer's charge with the adjustment to the charge occurring at the next network bill (noting that the published rates will continue to apply to CACs). New tariffs will be created in the case of new ICC or

CAC connections during 2018-19, in line with the methodology set out in this Pricing Proposal.

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

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

5.2.2 Alternative Control Services adjustments within 2018-19

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

5.3 Changes between regulatory years

Rule Requirement

Clause 6.18.2 Pricing proposals

(b) A pricing proposal must:

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

This Pricing Proposal contains several changes since 2017-18. These changes, largely reflecting our TSS, are outlined below.

5.3.1 Changes to the revenue requirement

This section outlines changes in our revenue between 2017-18 and 2018-19, including:

- adjustments to the TAR components
- Jurisdictional schemes
- DPPC (or TUOS).

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

Table 5-3 Summary of annual revenue adjustments

Component	2017-18 values	2018-19 values	Reason for change
CPI	1.48%	1.91%	Adjustment as per information published by the ABS – CPI All Groups, Average of Eight Capital Cities from the December quarter in 2016 to the December quarter in 2017.
X Factor	-19.59%	5.26%	X-factor updated in PTRM
Capital contributions	N/A	N/A	No longer applicable since 2017-18.
STPIS	$27.86 m	$27.72 m	The applicable S-factor for the year is 0.058%. It has been adjusted to reflect the previous year's S-factor.
DMIS Carry-over	N/A	N/A	Not applicable since 2017-18.
DUOS under/over recovery	$7.47 m	-$45.61 m	DUOS over recovery in 2016-17 to be returned to customers in 2018-19.
SBS FiT payments pass-through	N/A	N/A	No longer applicable since 2017-18.
Jurisdictional schemes	$0.0 m	$0.0 m	Set to nil following the Queensland Government's direction not to pass through jurisdictional scheme amount.
DPPC (TUOS)	$328.49 m	$304.23 m	-7.4% decrease in Powerlink charges between 2017-18 and 2018-19.

5.3.2 Network tariff changes for Standard Control Services

As noted in Section 1.5 of this Pricing Proposal, we are proposing a number of changes to our network tariffs for Standard Control Services from 1 July 2018. The main changes include the introduction of two new cost reflective network tariffs:

- an innovative residential seasonal time-of-use tariff, the Lifestyle tariff
- a time-of-use demand based tariff for SAC large customers.

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

Residential Lifestyle tariff

On 1 July 2018, we will offer a new residential tariff, NTC6400 – Residential Lifestyle (Lifestyle Tariff) available to residential customers with smart meters and consumption less than 100 MWh per year. Access to the tariff is limited to a specified number of customers as it is subject to the threshold tariff provisions set out in the NER.[20]

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

The main feature of the Lifestyle Tariff is to create a link between the cost of using the network and a customer's daily usage (expressed in kWh) of the network between 4pm and 9pm on any day in the summer season of November to March (the summer peak window). Customers can pay for their network usage during the summer peak window entirely on a pay as you use basis (choosing Band 1) or on a smoothed basis by paying a higher monthly charge (nominating Bands 2 to 5) that buys the right to access the network up to an agreed allocation of energy during the summer peak window. Should the customer's use of the network exceed the summer peak window allocation, a top-up charge will apply. There is no top-up charge for use of the network anytime outside of the summer peak window (April to October).

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

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

Table 5-4 Lifestyle tariff bands

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

Notes:

a. This relates to the right to use the network to access up to an agreed allocation of energy during the summer peak window without incurring top-up charges.

b. The examples of lifestyle options set out in this table are for illustrative purposes only and not intended to be a means by which assignment to a band will occur.

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

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

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

Table 5-5 Alignment with pricing principles

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

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

- The AER, the affected retailers and affected retail customers have been notified no later than four months before the start of the regulatory year – This condition is met by:
    - informing the AER during the course of 2017 of our intention to offer a new innovative tariff to a limited number of residential customers
    - including the new proposed Lifestyle tariff in this Pricing Proposal
    - seeking the introduction of the new voluntary Lifestyle tariff to be gazetted and included in the notified prices for regional Queensland in February 2018. As part of the Queensland Competition Authority's engagement process, we are of the view that retailers and customers have been informed of our intention to offer the new tariff from 1 July 2018.[21]
    - updating our website.

[21] It should also be noted that Energy Queensland has sought the introduction of the new voluntary Lifestyle tariff to be gazetted and included in the notified prices for regional Queensland. Following stakeholder engagement in February 2018, the Queensland Competition Authority, in its Draft Determination, endorsed the trial of the proposed tariff (T15). Refer Queensland Competition Authority's Draft Determination on Regulated Retail Electricity Prices for 2018-19, February 2018.

- The forecast revenue from the relevant tariff during each regulatory year in which the tariff is to apply is no greater than 0.5 per cent of our annual revenue requirement for that regulatory year (the individual threshold) – This condition is met by limiting the maximum number of residential customers taking up the Lifestyle tariff to 8,200 customers[22], to ensure the expected revenue to be recovered from that tariff to remain below the allowable threshold of $8.36 m; and

- Our forecast revenue from the relevant tariff, as well as from all other relevant tariffs, during each regulatory year in which those tariffs are to apply is no greater than one per cent of our annual revenue requirement for that regulatory year (the cumulative threshold) – This obligation is not relevant as there are no other relevant tariffs that would invoke the use of the cumulative threshold.

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

LV Demand Time-of-Use tariff

In accordance with the TSS, from 1 July 2018 a new voluntary cost reflective tariff, NTC7200 – LV Demand Time-of-Use, will be offered to LV large customers with consumption greater than 100 MWh per year. Since 1 July 2015, SAC large customers have been exposed to kVA-based demand charging. In response to customers' and stakeholders' expectations, the new tariff introduces time-of-use to the demand charging parameter.

The tariff structure of NTC7200 is as follows:

- Fixed charge ($/day)

- Usage charge (c/kWh)

- Demand charge ($/kVA/month)

- Excess demand charge ($/kVA/month)

The charging window for the new cost reflective tariff NTC7200 is between 9am and 9pm workdays.[23] The rationale for selecting this window is detailed in the TSS.

In addition to having a time-of-use demand charging parameter, we propose to include an excess demand rate. This excess demand rate will be cheaper than the peak demand rate, reflecting the fact that off-peak network usage is less likely to contribute to network augmentation requirements. This change would encourage customers with discretionary load to move their network usage into off-peak hours.

The excess charge is based on the maximum of:

- Zero,

22 Conservative estimate based on the assumption that all residential customers who agreed to participate to the trial have chosen Monthly Band 1 (the most expensive option).

23 Workdays are weekdays but exclude government specified public holidays.

- Maximum kVA demand measured as a single peak over a 30 minute period between 9 pm and 9 am on workdays or anytime on non-workdays, minus the peak demand quantity.

Small customers may voluntarily access this tariff. Customers must have appropriate Type 1-4 metering to access this tariff.

As demonstrated in Table 5-6 below, we consider that the new tariff aligns with pricing principles set out in NER.

Table 5-6 Alignment with pricing principles

Pricing principles	Alignment
Cost reflectivity	The tariff has been designed to address cross subsidies by reflecting the true cost of using the network by incorporating time-of-use to the kVA-based demand charge. It also encourages more efficient use of the network.
Tariff being based on LRMC	This principle is met by incorporating 100 per cent LRMC in the demand charging parameter of the tariff.
Customer impact	The timing for introducing this new tariff reflects a sufficient period for SAC Large customer to adjust to kVA based charging, introduced on 1 July 2015. It also should be noted that NTC7200 is offered on a voluntary basis.

5.3.3 Alternative Control Services changes

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

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

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

- Certain services needed to be restructured and disaggregated into various charging components to reflect the possible permutations introduced by metering service contestability

- Certain services, such as meter installations, were discontinued

- Certain services had to be duplicated to allow charging to either the customer or metering co-ordinator.

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

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

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

Rule Requirement

Clause 6.18.2 Pricing proposals

(b) A pricing proposal must:

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

The proposed 2018-19 prices for Standard Control Services included in this Pricing Proposal have been developed on the same basis as the 2018-19 indicative prices submitted last year as part of the 2017-18 Pricing Proposal and included in the 2017-18 Indicative Pricing Schedule. However, the indicative prices in the 2017-18 Indicative Pricing Schedule were based on inputs which have since been updated.

The proposed 2018-19 prices for certain Alternative Control Services have not been developed on the same basis as the indicative prices set out in the indicative Pricing Schedule submitted as part of the 2017-18 Indicative Pricing Schedule. Following the commencement of Power of Choice on 1 December 2017, the metering provision components have been separated from Alternative Control Services.

We note that the NER obligation only requires us to provide (and explain material differences) for our Direct Control Services (i.e. Standard Control Services (DUOS) and Alternative Control Services). While the 2017-18 Indicative Pricing Schedule also provides indicative prices for TUOS and jurisdictional scheme charges, we have focused our explanation mainly on the differences in our DUOS and Alternative Control Services prices.

5.4.1 Differences in Standard Control Services pricing levels

To satisfy clause 6.18.2(b)(7A) of the NER we have included a comparison between a comparison in price levels between the 2018-19 indicative rates set out in the 2017-18 Indicative Pricing Schedule and the proposed rates submitted as part of this Pricing Proposal in the (confidential) Tariff Approval Model and Attachment 3.

The calculation of individual rates is impacted by a number of inputs which have been updated between the development of the 2017-18 Indicative Pricing Schedule and this Pricing Proposal. The key changes include:

- the final TAR which has decreased by $103 million or 7 per cent
- the forecast DPPC revenue which has decreased by a $24 million down or 7.4 per cent

- updated customer numbers, demand and volume forecasts by tariff. Tariff rate outcomes can be quite sensitive to changes in these inputs, particularly in the case of relatively small customer and revenue allocations to a tariff class.

The overall NUOS revenue impact (TAR and DPPC revenues) is a decrease of $127 million or 7 per cent.

In addition, the overall forecast billable kVA demand and overall forecast volume have been adjusted. However, it should be noted that increases and decreases in forecast demand and energy vary across tariffs differently.

Tariff rate outcomes can be quite sensitive to changes in these inputs, particularly in the case of tariffs with relatively small customer and revenue allocations.

Furthermore, with the introduction of LRMC based cost reflective tariffs, and the associated progressive transition of legacy tariffs to 100 per cent LRMC based revenue recovery in their demand charge parameter, small variations in key inputs may have a magnified impact on the usage volumetric rate (c/kWh) which is used to recover the residual revenue after subtracting daily supply and demand charges.

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

With respect to materiality, we have referenced a raw increase of greater than 15 per cent in an individual rate and greater than 1.0 per cent in the indicative weighted outcome as the threshold to explain differences.

5.4.2 Reasons for differences in Alternative Control Services pricing levels

The price cap control mechanism that applies to our Alternative Control Services constrains movements in prices to a certain level. Any differences between our indicative 2018-19 prices set out in the 2017-18 Indicative Pricing Schedule and the proposed prices in this Pricing Proposal are limited to the adjustment to the CPI from 1.48 per cent to 1.91 per cent.

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

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

5.5 Updated indicative pricing levels

Rule Requirement

Clause 6.18.2 Pricing proposals

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

Attachment 2 sets out our latest estimates of indicative prices for the remaining year of the current regulatory control period (2019-20) for both our Standard and Alternative Control Services. These prices are based on tariff structures detailed in our TSS and current expectations regarding annual pricing inputs. Prices for our fee based services (capped price), Default Metering Services and Public Lighting Services will be escalated in accordance with the price cap formulae approved by the AER in the Distribution Determination set out in Equation 4-1.

The underlying assumptions we have applied for each type of charge relating to our Standard Control Services are set out in Table 5-7 below.

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

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

Table 5-7 Assumptions underpinning the expected price trends for Standard Control Services

Type of charge	Assumptions
DUOS	• Applied the revenues from the Distribution Determination, with no adjustments for the s-factor, inflation or the return on debt. In practice, the AER is likely to approve adjustments for these factors, in accordance with the revenue cap formula. • Did not include any forecast DUOS over or under-recovery adjustment in 2019-20. • Used high level assumptions regarding: ○ energy and demand ○ customer numbers ○ customer churn.
DPPC (TUOS)	• Based on the 2018-19 DPPC revenue figure adjusted using forecast CPI • Did not include any forecast DPPC over or under-recovery

	adjustment.

5.6 Publication of information about tariffs and tariff classes

Rule Requirement

Clause 6.18.9 Publication of information about tariffs and tariff classes

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

(2) its current indicative pricing schedule

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

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

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

The NER also prescribes timeframes, in which Energex must publish this information.[24]

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

[24] NER, clauses 6.18.9(a1) and (b),

Appendices

Appendix 1: Proposed network tariffs and charging parameters

Consistent with our TSS, Table A1- 1 to Table A1- 7 below set out the tariffs and tariff structures for Standard Control Services for primary and secondary tariffs offered in 2018-19.

Standard Control Services tariffs and tariff structures for primary tariffs for 2018-19

Table A1- 1 Tariffs and tariff structures for customers connected at 33kV and above

Tariff	Tariff description	Charge	Charging parameter	Implementation
ICC (NTC1000)	Customers in the ICC tariff class are assigned to this tariff.	Supply charge	Unit: $/day (these charges vary for each customer).	Default tariff.
		Time-of-use usage charge	Unit: c/kWh Peak and off-peak timeframes defined in Table A1- 8.	
		Demand charge	Unit: $/kVA/month Quantity: Maximum kVA demand measured over a 30 minute period during the billing period.[a]	
		Capacity charge	Unit: $/kVA/month.	

Note:

a. The average power used during the 30 minute period is used to calculate demand.

Table A1- 2 Tariffs and tariff structures for customers connected at 11kV

Tariff	Tariff description[a]	Charge	Charging parameter	Implementation
11kV Bus (NTC4000)	Customers with a network coupling point at an 11 kV zone substation bus via a dedicated 11 kV feeder that is not shared with any customer.	Supply charge	Unit: $/day (these charges vary for each customer).	Default for customers with an 11kV bus configuration.
		Usage charge	Unit: c/kWh Quantity: Peak and off-peak timeframes are defined in Table A1- 8.	
		Demand charge	Unit: $/kVA/month Quantity: Maximum kVA	

Tariff	Tariff description[a]	Charge	Charging parameter	Implementation
			demand measured over a 30 minute period during the billing period.[b]	
11kV Line (NTC4500)	Customers with a network coupling point at an 11 kV feeder shared with other customers.	Supply charge	Unit: $/day (these charges vary for each customer).	Grandfathered since 1 July 2017.
		Usage charge	Unit: c/kWh. Quantity: Peak and off-peak timeframes defined in Table A1- 8.	
		Demand charge	Unit: $/kVA/month. Quantity: Maximum kVA demand measured over a 30 minute period during the billing period.[b]	
HV Demand (NTC8000)	Previously, this tariff was allocated to 11 kV customers with energy less than 4 GWh per year and demand less than 1 MVA. From 1 July 2017, new customers with these characteristics are allocated to either NTC7400 – Demand Time-of-Use 11 kV if they share an 11 kV feeder with other customers or to NTC4000 – 11 kV Bus if they have an 11 kV bus configuration.	Supply charge	Unit: $/day (these charges vary for each customer).	Grandfathered since 1 July 2015.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	
		Demand charge	Unit: $/kVA/month. Quantity: Maximum kVA demand measured over a 30 minute period during the billing period.[b]	
EG – 11kV (NTC3000)	Previously, this tariff was allocated to customers who were predominantly generation customers with a generation capacity greater than 30 kVA.	Supply charge	Unit: $/day (these charges vary for each customer).	Grandfathered since 1 July 2015.
		Usage charge	Unit: c/kWh. Quantity: Peak and off-peak timeframes defined in Table A1- 8.	

Tariff	Tariff description[a]	Charge	Charging parameter	Implementation
	From 1 July 2017, new customers with these characteristics are allocated to either NTC7400 – Demand Time-of-Use 11 kV if they share an 11 kV feeder with other customers or to NTC4000 – 11 kV Bus if they have an 11 kV bus configuration.	Demand charge	Unit: $/kVA/month Quantity: Maximum kVA demand measured over a 30 minute period during the billing period.[b]	
Demand Time-of-Use 11kV (NTC7400)[c]	Cost reflective time-of-use demand tariff for customers with a network coupling point at 11 kV feeder shared with other customers.	Supply charge	Capital: Unit: $/day/$M of non-contributed asset value (NCCAV). Quantity: NCCAV ($M) and number of days in billing period. Operating and maintenance: Unit: $/day/$M connection asset value (CAV). Quantity: CAV ($M) and number of days in billing period.	Tariff offered from 1 July 2017 on a voluntary basis for all existing 11kV Line customers on legacy tariffs. This tariff became the default tariff from 1 July 2017 for new customers that share an 11kV feeder with other customers.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	
		Peak Demand charge	Unit: $/kVA/month. Quantity: Maximum kVA demand measured as a single peak over a 30 minute period during charging window defined in Table A1- 9.	
		Excess demand charge	Unit: $/kVA/month. Quantity: The maximum of: • Zero,	

Tariff	Tariff description[a]	Charge	Charging parameter	Implementation
			• Maximum kVA demand measured as a single peak over a 30 minute period outside the peak charging windows defined in Table A1- 9, minus the peak demand quantity as described above.[b]	

Notes:

a. It should be noted that connection assets are the assets required to connect an electrical installation to the shared network, and are all the assets from the connection point back up to and including the network coupling point.
Dedicated connection assets are generally for the sole use of a single connection and are typically not shared by multiple connections. In circumstances where the network coupling point, and/or identification of dedicated connection assets, is unclear or contested, Energex will consider other information, including but not limited to, the customer's metering point to make a determination about the network coupling point.

b. The average power used during the 30 minute period is used to calculate demand.

c. Proposed new tariff.

Table A1- 3 Tariffs and tariff structures for LV customers with consumption greater than 100 MWh/year

Tariff	Tariff description	Charge	Charging parameter	Implementation
Large Demand (NTC8100) Small Demand (NTC8300)	Tariffs available to LV customers with consumption greater than 100 MWh per year. LV customers with consumption less than 100 MWh per year may voluntarily access these tariffs. Customers must have appropriate Type 1-4 metering to access these tariffs.	Supply charge	Unit: $/day. Quantity: Days in billing period.	NTC8100: Optional tariff. NTC8300: Default tariff.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	
		Demand charge	Unit: $/kVA/month. Quantity: Maximum kVA demand measured over a 30 minute period during the billing period.[a]	
LV Demand Time-of-Use (NTC7200)	Tariff available to LV customers with consumption greater than 100 MWh per year. LV customers with	Supply charge	Unit: $/day Quantity: Days in billing period.	Tariff offered from 1 July 2018 on a voluntary basis.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing	

Tariff	Tariff description	Charge	Charging parameter	Implementation
	consumption less than MWh per year may voluntarily access this tariff. Customers must have appropriate Type 1-4 metering to access this tariff.		period.	
		Demand charge	Unit: $/kVA/month. Quantity: Maximum kVA demand measured as a single peak over a 30 minute period during charging window defined in Table A1- 9.[a]	
		Excess demand charge	Unit: $/kVA/month. Quantity: The maximum of: • Zero, • Maximum kVA demand measured as a single peak over a 30 minute period outside the peak charging windows defined in Table A1- 9, minus the peak demand quantity as described above.[a]	

Note:

a. The average power used during the 30 minute period is used to calculate demand.

Table A1- 4 Tariffs and tariff structures for residential customers

Tariff	Tariff description	Tariff structure	Charging parameter	Implementation
Residential Flat (NTC8400)	This tariff is the default tariff for residential customers regardless of their size and cannot be used in conjunction with Residential Time-of-Use (NTC8900).	Supply charge	Unit: $/day. Quantity: Days in billing period.	Default tariff.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	
Residential Time-of-Use	This tariff is available to	Supply charge	Unit: $/day. Quantity: Days in	Optional tariff.

Tariff	Tariff description	Tariff structure	Charging parameter	Implementation
(NTC8900)	residential customers regardless of their size and cannot be used in conjunction with Residential Flat (NTC8400). Customers must have a time-of-use capable meter to access this tariff.		billing period.	
		Usage charge	Unit: c/kWh. Quantity: kWh in billing period. Peak, shoulder and off-peak timeframes defined in Table A1- 8.	
Residential Demand (NTC7000)	This tariff is available to residential customers regardless of their size and cannot be used in conjunction with Residential Flat (NTC8400). Customers must have appropriate Type 1-4 metering to access this tariff.	Supply charge	Unit: $/day. Quantity: Days in billing period.	Optional tariff.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	
		Demand charge	Unit: $/kW/month. Quantity: Maximum kilowatt demand measured as a single peak over a 30 minute period during peak charging window defined in Table A1-9.[a] For the first 12 months on this tariff, eligible customers' chargeable demand will be capped. Terms and conditions are provided in Appendix 3.	
Residential Lifestyle (NTC6400)	This tariff is available to residential customers with consumption less than 100 MWh per year. Customers must have appropriate Type 1-4 metering to access this tariff.	Network access allowance[b,c]	Unit: $/month (based on customer's nominated Access Band set out in Table A1-11) Quantity: Month in billing period.	Threshold tariff available to a limited number of residential customers specified in Section 5.3.2.
		Summer peak top-up	Unit: $/kWh/month Quantity: based on the	

Tariff	Tariff description	Tariff structure	Charging parameter	Implementation
		charge[d,e,f]	maximum of: • Zero; or • The single maximum daily energy accessed above the threshold associated with the nominated band during the billing period. Applies to network use during the summer peak charging window defined in Table A1- 9.	
		Usage flat[g,h]	Unit: c/kWh Quantity: kWh in billing period	

Notes:

a. The average power used during the 30 minute period is used to calculate demand.
b. Customers can choose the band option that matches their maximum use in the summer peak window and payment preferences.
c. Once choice of an access band is made, customers cannot choose a lower band until they have been on the chosen band for a full 12 months. Customers, however, can choose to move to increase their network access allowance by moving to a higher band at any time.
d. The summer peak top-up rate is the same regardless of the chosen band.
e. There is no top up charge for exceeding the agreed allowance anytime outside of the summer peak window.
f. Once the allocation is exceeded, the increased amount remains available for the rest of the month and then resets back to the original nominated allowance at the start of the month.
g. The volume rate is the same regardless of the chosen band.
h. The anytime volume charge applies to all energy supplied from the grid.

Table A1- 5 Tariffs and tariff structures for LV business customers with consumption less than 100 MWh/year

Tariff	Tariff description	Tariff structure	Charging parameter	Implementation
Business Flat (NTC8500)	This tariff is the default tariff for business customers with consumption less than 100 MWh per year.	Supply charge	Unit: $/day. Quantity: Days in billing period.	Default tariff.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	
Business Time-of-Use (NTC8800)	This tariff is available to business customers with consumption less than 100 MWh per year. Customers must have time-of-use capable metering installed to access this tariff.	Supply charge	Unit: $/day. Quantity: Days in billing period.	Optional tariff.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing period. Peak and off-peak timeframes defined in Table A1- 8.	
Business Demand (NTC7100)[a]	This tariff is available to business customers with consumption less than 100 MWh/year and cannot be used in conjunction with Business flat (NTC8500). Customers must have appropriate Type 1-4 metering to access this tariff.	Supply charge	Unit: $/day. Quantity: Days in billing period.	Optional tariff offered from 1 July 2017.
		Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	
		Demand charge	Unit: $/kW/month. Quantity: Maximum kilowatt demand measured as a single peak over a 30 minute period during peak charging window defined in Table A1- 9.[b]	

Notes:

a. Proposed new tariff.
b. The average power used during the 30 minute period is used to calculate demand.

Tariff and tariff structure for unmetered supplies

This tariff is applicable to unmetered supplies. This includes facilities such as street lighting, public telephones, traffic signals, and public barbecues and watchman lights. Energex only provides connection to the network for these services. The unmetered supply tariff therefore seeks to only recover a contribution towards the shared network (use of system charge).

Table A1- 6 Tariffs and tariff structure for the unmetered tariff

Tariff	Tariff structure	Charging parameter	Implementation
Unmetered (NTC9600)	Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	Default tariff.

Tariffs and tariff structures for secondary tariffs

Load control tariffs are secondary tariffs for residential customers which can only be used in conjunction with a primary tariff in the SAC tariff class.

Energex's tariffs, tariff structures and implementation for load control tariffs are outlined in Table A1- 7 below.

Table A1- 7 Tariffs and tariff structures for load control tariffs

Tariff	Tariff structure	Charging parameter	Implementation
Super Economy (NTC9000)[a] Economy[a] (NTC9100)	Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	Optional secondary tariff.
Smart Control[b] (NTC7300)	Usage charge	Unit: c/kWh. Quantity: kWh in billing period.	Optional secondary tariff in conjunction with the residential demand tariff, NTC7000 – Residential Demand.

Notes:

a. This tariff cannot be used in conjunction with NTC7000.

b. Proposed new tariff.

The terms and conditions for secondary tariffs can be found in Appendix 2 of this Pricing Proposal.

Time-of-use charging timeframes

The charging timeframes for time-of-use usage and time-of-use demand tariffs are included in Table A1- 8 and Table A1- 9 below.

Table A1- 8 Time-of-use usage charging timeframes

Tariff	Network Tariff Code	Charging timeframes	Weekdays[a]	Weekends
Residential Time-of-Use	NTC8900	Off-Peak	10pm – 7am	10pm – 7am
		Shoulder	7am – 4pm, 8pm – 10pm	7am – 10pm
		Peak	4pm – 8pm	No peak
Business Time-of-Use	NTC8800	Off-Peak	9pm – 7am	Anytime
		Peak	7am – 9pm	No peak
ICC, CAC	NTC1000 NTC4000 NTC4500 NTC3000	Off-Peak	11pm – 7am	Anytime
		Peak	7am – 11pm	No peak

Note:
a. Include government specified public holidays.

Table A1- 9 Time-of-use demand charging windows

Tariff	Network Tariff Code	Charging timeframes	Workdays[a]	Weekends
Residential Time-of-Use	NTC7000	Off-Peak	8pm – 4pm	Anytime
		Peak	4pm – 8pm	No peak
Business Time-of-Use	NTC7100 NTC7200 NTC7400	Off-Peak	9pm – 9am	Anytime
		Peak	9am – 9pm	No peak

Note:
a. Workdays are weekdays but exclude government specified public holidays.

The charging timeframes for the top-up summer peak charge is set out in Table A1- 10 below.

Table A1- 11 Residential Lifestyle tariff charging window

Tariff	Network Tariff Code	Charging timeframes	Season	Days[a]
Residential Lifestyle	NTC6400	Summer peak window	November to March	Any day 4pm – 9pm

Note:
a. Include weekdays, weekends and government specified public holidays during summer peak window.

Residential Lifestyle Tariffs network access bands

The customer's nominated access bands are set out in Table A1-11 below.

Table A1- 11 Residential Lifestyle Tariff Network Access Bands

Network access allowance	Summer peak window (SPW) network allowance in the band
Access Band 1	0 kWh
Access Band 2	Up to 5 kWh
Access Band 3	Up to 10 kWh
Access Band 4	Up to 15 kWh
Access Band 5	Up to 20 kWh

Appendix 2: Terms and conditions for secondary tariffs

1. Secondary tariffs terms and conditions

1.1 Overview

Energex provides customers with the opportunity to obtain supply through circuits which are connected to Energex's load control mechanisms and charged through Energex's load control tariffs. These load control tariffs are secondary tariffs as they can only be accessed as adjuncts to a primary tariff.

Energex provides a load control option to customers because the ability to manage load at Energex's discretion provides network advantages. The customer benefits from being charged a usage rate for the supply of electricity that recognises the network benefits which Energex gains from this ability to control load.

The ongoing provision of load controlled supply metered via load control tariffs to a customer's premise is at Energex's discretion. This discretion will be exercised in accordance with the fair use policy and the rules related to those particular tariffs set out below.

In addition to the conditions listed below, in extreme or emergency conditions Energex as an alternative to removing all supply, reserves the right to control the load for periods in excess of the times stated in the tariff conditions.

1.2 Fair Use policy

All secondary tariffs must be accessed as an adjunct to a primary tariff at the customer's premises. Secondary tariffs are not priced, or intended, to be the tariff which supplies the main light and power load for premises.

Customers who utilise a mix of wiring, appliances and technologies, or any other means, in such a manner as to generally supply the energy needs of their light and power for their premises through secondary tariffs, to the detriment of their use of their primary tariff, will be excluded from access to secondary tariffs.

This fair use policy will not exclude access to secondary tariffs for customers with solar PV or other micro generation who register very low consumption on the primary tariff because they consume large amounts of self-generated power, or for customers who naturally have very low consumption of light and power.

1.3 NTC9000 Super Economy

(a) <u>Availability</u>

The tariff is available as a secondary tariff provided it is used in conjunction with a primary tariff at the same NMI. However this tariff cannot be used in conjunction with NTC7000 – Residential Demand. Supply to the controlled load circuit will be available for a minimum of 8 hours per day. Load will be managed to maintain customer comfort, maximise utilisation and minimise peak demand on the Energex network. The time when supply is available is subject to variation at Energex's absolute discretion.

(b) Technical Requirements

(i) All loads supplied by the tariff must be supplied by a dedicated circuit and controlled by an Energex approved Network Load Control Device.

(ii) The premises must have been wired in accordance with the requirements of the Queensland Electricity Connections and Metering Manual (QECMM) at the time of requesting access to the tariff.

(iii) General light and power cannot be supplied directly or indirectly from electricity supplied under NTC9000 – Super Economy and must be supplied from a primary tariff or self-generation.

(iv) The customer can only connect items on the Approved List set out at item 1.5 below to NTC9000.

(v) Electricity supply must be permanently connected to the items on the Approved List, except for electric vehicle supply equipment / EV Chargers or pool filtration systems which can be supplied through a dedicated socket-outlet.

(c) Restrictions

This tariff will not be available, and will be removed from any premises, where the customer has the ability to supply the appliance or asset via another means (changeover switch to a primary tariff) of supplying such appliance or asset in the periods during which supply is not available under this tariff.

1.4 NTC9100 Economy

(a) Availability

The tariff is available as a secondary tariff provided it is used in conjunction with a primary tariff at the same NMI. However this tariff cannot be used in conjunction with NTC7000 – Residential Demand. Supply to the controlled load circuit will be available for a minimum of 18 hours per day. Load will be managed to maintain customer comfort, maximise utilisation and minimise peak demand on the Energex network. The time when supply is available is subject to variation at Energex's absolute discretion.

(b) Technical Requirements

(i) All loads supplied by the tariff must be supplied by a dedicated circuit and controlled by an Energex approved Network Load Control Device.

(ii) The premises must have been wired in accordance with the requirements of the QECMM at the time of requesting access to the tariff.

(iii) General light and power cannot be supplied directly or indirectly from electricity supplied under NTC9100 – Economy and must be supplied from a primary tariff or self-generation.

(iv) The customer can only connect items on the Approved List set out at item 1.5 below to NTC9100.

(v) Electricity supply must be permanently connected to the items on the Approved List, except for electric vehicle supply equipment / EV chargers or pool filtration systems which can be supplied through a dedicated socket-outlet.

(c) Restrictions

This tariff will not be available, and will be removed from any premises, where the customer has the ability to supply the appliance or asset via another means (changeover switch to a primary tariff) to supply such appliance or asset in the periods during which supply is not available under this tariff.

1.5 Approved List

Only the following appliances or machines can be connected to NTC9000 – Super Economy or NTC9100 – Economy:

(i) Electric storage water heaters with thermostatically controlled or continuously operating heating units.

(ii) Boost elements of solar-heated water heaters.

(iii) Electric Vehicle Supply Equipment (EV Chargers).

(iv) Pool filtration systems.

(v) Heat pump water heaters.

(vi) Other domestic appliances (e.g. air conditioners, washing machines and dishwashers) except where the appliance is duplicated in order that supply may be obtained on a different tariff for the same purpose during the restricted period.

1.6 NTC7300 – Smart Control

(a) Availability

NTC7300 – Smart Control is available for the supply of controllable residential loads, as a secondary tariff for residential customers on NTC7000 – Residential demand, or other primary demand tariffs including NTC8100 or NTC8300.

For appliances connected to audio frequency load control relays, supply will be available for typically 12 hours per day. For customers transferring from NTC9000 or NTC9100 their existing switching times will be maintained until the audio frequency load control relay is reprogramed in accordance with Energex's requirements.

For Peak Smart air-conditioners the device may be limited to 75% or 50% of rated capacity for periods of up to four hours up to twelve times per year.

Demand will be managed to maintain customer comfort, maximise utilisation and minimise peak demand on the Energex network. The time when demand is managed is subject to variation at Energex's absolute discretion.

(b) Technical Requirements

(i) The customer must have appropriate advanced metering for both the primary and secondary tariffs.

(ii) The metering must be capable of measuring import and export energy and providing Energex with power quality data on request.

(iii) All appliances supplied by NTC7300 must be supplied by a dedicated circuit and controlled by an Energex approved Network Load Control Device.

(iv) Electricity supply must be permanently connected to the items on the Approved List, except for electric vehicle supply chargers / EV chargers or pool filtration systems which can be supplied through a dedicated socket-outlet.

(v) The premises and load control devices must have been wired in accordance with the requirements of the QECMM at the time of requesting access to the tariff.

(vi) The customer can only have items on the Approved List set out at item 1.7 below supplied by NTC7300.

(vii) General light and power cannot be supplied directly or indirectly from electricity supplied under NTC7300 and must be supplied from a primary tariff or self-generation.

(c) Restrictions

NTC7300 will not be available, and may be removed from any premises, where:

(i) The customer has the ability to supply the appliance or asset via another means (changeover switch to a primary tariff) to supply such appliance or asset in the periods during which supply is not available under this tariff; or

(ii) The load control device or Demand Response Enabling Device (DRED) is tampered with or removed.

(d) Enforcement

Energex will run automated queries on the energy consumption data for all customers connected to NTC7300 – Smart Control to identify inoperable load control devices. When a load control device is found to not be responding to demand response signals Energex will:

(i) Notify the customer that load control devices are not operating and advise the customer to contact their service provider and have the load control device repaired or replaced.

(ii) If the failure is caused by a problem with the Energex communications or control system Energex will reimburse the customer the cost of the service call.

(iii) Whilst the load control device is inoperable, from the start of the next billing month the energy consumption data from NTC7300 – Smart Control circuit will be added to the applicable primary demand tariff NTC7000, NTC8100 or NTC8300 for the purposes of network billing.

(iv) Once the customer has had the load control rectified they must reapply to Energex to be moved back to NTC7300 – Smart Control.

1.7 Approved List

Only the following appliances or machines can be connected to NTC7300 – Smart Control:

(i) Electric storage water heaters with thermostatically controlled or continuously operating heating units.

(ii) Boost elements of solar-heated water heaters.

(iii) Air conditioners compliant with AS/NZS4755 and fitted with a DRED.

(iv) Pool filtration systems.

(v) Electric Vehicle Supply Equipment (EV Chargers).

(vi) Battery Energy Storage Systems compliant with AS/NZS4755 and fitted with a DRED with export limited to a 5kW inverter (export in excess of this limit will require an assessment by Energex).

(vii) Other appliances compliant with AS/NZS4755 and fitted with a DRED.

(viii) Heat pump water heaters.

(ix) Other domestic appliances (e.g. air conditioners, washing machines and dishwashers) except where the appliance is duplicated in order that supply may be obtained on a different tariff for the same purpose during the restricted period.

1.8 Energex approved Load Control Devices

The following devices are required to control all appliances on economy tariffs:

(i) Audio frequency load control relays which disconnect supply from the circuit when signalled by Energex.

(ii) AS4755 appliances must be fitted with an Energex Approved DRED.

(iii) The prices for providing and installing load control equipment will be as set out in Energex's tariff schedule available at www.energex.com.au.

1.9 Safety issues

Clothes dryers are not recommended for connection to economy tariffs.

1.10 Battery Energy Storage Systems

Customers wanting to supply their light and power via a hard wired battery to gain the advantages of drawing electricity at cheaper usage rates should do so through the appropriate primary tariff.

Appendix 3: Financial Risk Reduction Mechanism terms and conditions

1.1 Overview

Since 1 July 2016, Energex has offered a demand tariff to residential customers on a voluntary basis. This initiative formed part of Energex's objective to gradually transition residential and small business network tariffs to full cost reflectivity. Further information on Energex's tariff reform is provided in Energex's 2017-20 TSS.

To ensure demand tariffs are understood and customers have sufficient time to adapt and respond to the tariff signals, Energex introduced a Financial Risk Reduction Mechanism (FRRM) for residential and small business customers for a fixed period of time. This mechanism is intended to provide a degree of bill protection to eligible customers while they are familiarising themselves with the new demand concept.

The terms and conditions detailing the criteria determining the eligibility of customers are provided below.

1.2 Terms and conditions

1) The FRRM applies to customers with the specified demand primary network tariffs NTC7000 – Residential Demand (Specified Demand Tariff).

2) Access to the FRRM is limited to customers with a Maximum Annual Consumption of 10 MWh at the time of adopting the Specified Demand Tariff.

3) The FRRM is available on a voluntary basis to the eligible customers on the day the Specified Demand Tariff applies.

4) The FRRM applies for a maximum of 12 months from the day an eligible customer has adopted a Specified Demand Tariff.
5) If the FRRM does not commence on the first day of the month, the demand cap will be applied on a pro rata basis for the first month. The mechanism will apply as if it had started on the first day of the month – to avoid confusion, if a customer starts on the residential demand tariff on 18 August 2016, the FRRM will end on 31 July 2017.
6) The FRRM applies for one continuous period only. Once the 12 month period begins, it continues until it is completed or until one of the events listed in (8) occurs, whichever comes earlier.

7) The FRRM is no longer available where an eligible customer or their retailer declines the initial offer of a FRRM when adopting a Specified Demand Tariff.

8) Access to the FRRM is removed if an eligible customer :
    a. Changes primary tariff
    b. Moves location
    c. Disconnects for reasons other than non-payment
    d. Changes account holder

e. Reverts from the Specified Demand Tariff to any other tariff, and then adopts a Specified Demand Tariff again.

9) Access to the FRRM is not removed if:

a. A customer transfers from one retailer to another, with the same tariffs

b. If a customer's consumption increases during the 12 month period the bill protection applies to.

10) The FRRM allows eligible customers to experience demand tariffs up to a Maximum Demand Cap of 5 kW.

11) The Maximum Demand Cap is updated on an annual basis at the sole discretion of Energex but in a manner that is consistent with the pricing principles set out in the National Electricity Rules.

12) All eligible customers are exposed to the same Maximum Demand Cap.

13) An eligible customer's monthly maximum demand used for the FRRM is determined in accordance with the approach detailed in the relevant Energex TSS for the relevant Specified Demand Tariffs.

14) The FRRM can be manually end-dated immediately if a customer or their retailer does not wish to partake in it.

Appendix 4 – Summary of compliance

Table A4- 1

Compliance with the National Electricity Rules

Clause	Obligation	Demonstration in this Pricing Proposal
5.5(h) and (i)	Energex must pass through to a connection applicant the amount (calculated in accordance with paragraph (i)) for the locational component of prescribed TUoS services that would have been payable by Energex to Powerlink had the connection applicant not been connected to its distribution network ('avoided charges for the locational component of prescribed TUoS services').	Section 3.3.2.3 and Table 3-9.
6.1.4(a)	Energex must demonstrate that it does not charge a Distribution Network User DUOS charges for the export of electricity generated by the user into the distribution network.	Section 3.2.3.
6.1.4(b)	Energex must demonstrate that it charges for the provision of connection services as allowed in the NER.	Chapter 3 and Chapter 4.
6.18.1A(c)	Energex must comply with the tariff structure statement approved by the AER and any other applicable requirements in the NER, when Energex is setting the prices that may be charged for direct control services.	Tariffs calculated as part of this Pricing Proposal have been developed consistent with our TSS. Energex has demonstrated compliance with our AER-approved TSS throughout this Pricing Proposal.
6.18.1C(a)(1) and (2)	No later than four months before the start of a regulatory year (other than the first regulatory year of a regulatory control period), Energex may notify the AER, affected retailers and affected of a new proposed tariff (a relevant tariff) that is determined other than in accordance with Energex's Tariff Structure Statement , if the following conditions are satisfied: 1) the forecast revenue from the relevant tariff during each regulatory year in which the tariff is to apply is not greater than 0.5 per cent of Energex's annual revenue requirement for that regulatory year (the individual threshold); and 2) the forecast revenue from the relevant tariff, as well as from all other relevant tariffs, during each regulatory year in which those tariffs are to apply is no greater than one per cent of Energex's annual revenue requirement for that regulatory year (the cumulative threshold).	Section 5.3.2.
6.18.2(a)(2)	Energex must submit to the AER, at least 3 months before the commencement of the second and each subsequent regulatory year of the regulatory control period, a further pricing proposal (an annual pricing proposal) for the relevant regulatory year.	Our Pricing Proposal was submitted on 31 March 2018.

Clause	Obligation	Demonstration in this Pricing Proposal
6.18.2(b)(2)	Energex's Pricing Proposal must set out for each tariff class the proposed tariff (including the tariffs and classes of Alternative Control Services) specified in the tariff structure statement for the relevant regulatory control period.	Section 2.1 and 2.2 (Standard Control Services). Section 4.1 (Alternative Control Services). The 2018-19 tariffs and tariff structures for Standard Control Services and Alternative Control Services are consistent with our TSS.
6.18.2(b)(3)	Energex's Pricing Proposal must set out, for each proposed tariff, the charging parameters and the elements of service to which each charging parameter relates.	Section 2.2 (Standard Control Services). Section 4.2 (Alternative Control Services).
6.18.2(b)(4)	Energex's Pricing Proposal must set out, for each tariff class related to standard control services, the expected weighted average revenue for the relevant regulatory year and also for the current regulatory year.	Section 3.2.4.
6.18.2(b)(5)	Energex's Pricing Proposal must set out the nature of any variation or adjustment to the tariff that could occur during the course of the regulatory year and the basis on which it could occur.	Section 5.2.
6.18.2(b)(6)	Energex's Pricing Proposal must set out how DPPCs are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those charges in the previous regulatory year.	Section 3.3.
6.18.2(b)(6A)	Energex's Pricing Proposal must set out how jurisdictional scheme amounts for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those amounts.	Section 3.4.
6.18.2(b)(6B)	Energex's Pricing Proposal must describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria.	There have been no changes to the jurisdictional schemes since their last jurisdictional scheme approval dates.
6.18.2(b)(7)	Energex's Pricing Proposal must demonstrate compliance with the NER and any applicable distribution determination, including Energex's TSS for the relevant regulatory control period.	This table (Table A4-1) demonstrates how Energex complies with the NER, the Distribution Determination and its TSS throughout this Pricing Proposal.
6.18.2(b)(7A)	Energex's pricing proposal must demonstrate how each	Section 5.5 Attachment 3

Clause	Obligation	Demonstration in this Pricing Proposal
	proposed tariff is consistent with the corresponding indicative pricing levels for the relevant regulatory year as set out in the indicative pricing schedule, or explain any material differences between them.	sets out the material differences between the 2018-19 indicative pricing levels (as set out in our 2017-18 Indicative Pricing Schedule) and the proposed 2018-19 tariffs included in Attachment 1 and the (confidential) Tariff Approval Model.
6.18.2(b)(8)	Energex's Pricing Proposal must describe the nature and extent of change from the previous regulatory year and demonstrate that the changes comply with the NER and any applicable distribution determination.	Section 5.3. How these changes comply with the NER and any applicable Distribution Determination is set out in this table (Table A4-1) and Table A4- 2.
6.18.2(d)	At the same time as Energex submits its pricing proposal, Energex must submit to the AER a revised indicative pricing schedule which sets out, for each tariff and for each of the remaining regulatory years of the regulatory control period, the indicative price levels determined in accordance with Energex's TSS for that regulatory control period and updated so as to take into account that pricing proposal.	Our revised indicative pricing schedule, updated to take into account this Pricing Proposal is set out in Attachment 2 provided as part of this Pricing Proposal. Indicative prices contained in the schedule have been calculated consistent with methodologies outlined in our TSS.
6.18.2(e)	Where Energex submits an annual pricing proposal, the revised indicative pricing schedule referred to in clause 6.18.2(d) must also set out, for each relevant tariff under clause 6.18.1C, the indicative price levels for that relevant tariff for each of the remaining regulatory years of the regulatory control period, updated so as to take into account that pricing proposal.	Attachment 2 includes indicative prices for the Lifestyle tariff offered under clause 6.18.1C.
6.18.3(b)	Energex must demonstrate that for each customer for direct control services is a member of one or more tariff class.	Section 2.1 (Standard Control Services) and Section 4.1 (Alternative Control Services) of this Pricing Proposal. Chapter 5, Section 6.4 and Appendix 3 and 4 of the TSS
6.18.3(c)	Energex must demonstrate that separate tariff classes have been constituted for standard control and alternative control customers. A customer for both standard control services and alternative control services may be a member of 2 or more	Section 2.1 and Section 4.1 of this Pricing Proposal. Section 3.1 and Section 6.1 of the TSS

Clause	Obligation	Demonstration in this Pricing Proposal
	tariff classes.	
6.18.3(d)(1)	Energex must demonstrate that tariff classes have been formed based on groupings of customers on an economically efficient basis.	Section 3.1 and Section 6.1 of the TSS Section 2.1 and Section 4.1 of the Pricing Proposal.
6.18.3(d)(2)	Energex must demonstrate that customers are grouped into tariff classes with regard to the need to avoid unnecessary transaction costs.	Section 3.1 and Section 6.1 of the TSS. Section 5.1 of the Explanatory Notes accompanying the TSS. Section 2.1 and Section 4.1 of the Pricing Proposal.
6.18.4(a)(1)(i), (ii) and (iii)	Energex must demonstrate that customers are assigned (or reassigned) to tariff classes on the basis of the nature and extent of their usage, the nature of their connection to the network, and the metering installed at the customer's premises.	Chapter 5, Section 6.4 and Appendix 3 and 4 of the TSS
6.18.4(a)(2)	Energex must demonstrate that customers with a similar profile are treated on an equal basis.	Chapter 5, Section 6.4 and Appendix 3 and 4 of the TSS
6.18.4(a)(3)	Energex must demonstrate that customers with micro-generation facilities are treated no less favourably than customers without such facilities but with a similar load profile.	Section 5.2 of the TSS
6.18.4(a)(4)	Energex must demonstrate that customer assignment (or reassignment) to a particular tariff class does not occur in the absence of an effective system of assessment and review.	Chapter 5, Section 6.4 and Appendix 3 and 4 of the TSS
6.18.4(b)	Energex must demonstrate that 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, an effective system of assessment and review should be provided of the basis on which a customer is charged.	Chapter 5, Section 6.4 and Appendix 3 and 4 of the TSS
6.18.5(a)	The network pricing objective is that the tariffs that Energex charges in respect of its provision of direct control services to a retail customer should reflect Energex's efficient costs of providing those services to the retail customer.	Chapter 3 and Chapter 4
6.18.5(b)	Subject to clause 6.18.5(c), Energex's tariffs must comply with the pricing principles.	Sections 3.2.6, 3.2.7, and 3.2.9 (Standard Control Services). Section 0 (Alternative Control Services).
6.18.5(c)	Energex's tariff may vary from tariffs which would result from complying with the pricing principles only: (1) to the extent permitted under clause 6.18.5(h) which	Chapter 6, Section 6.3 of the Explanatory Notes accompanying the TSS.

Clause	Obligation	Demonstration in this Pricing Proposal
	requires Energex to consider the impact of annual changes in tariffs on customers (2) to the extend necessary to give effect to the pricing principles.	
6.18.5(e)(1) and (2)	Energex must demonstrate that the revenue expected to be recovered from a tariff class lies between the stand alone and avoidable cost.	Section 3.2.6(Standard Control Services). Section 4.5.1 (Alternative Control Services). Section 2.2 of the TSS.
6.18.5(f)	Energex must demonstrate that its tariffs are based on the long-run marginal cost.	Section 3.2.7(Standard Control Services) Section 4.5.2 (Alternative Control Services) Section 2.3 of the TSS.
6.18.5(g)	The revenue expected to be recovered from each tariff must: (1) reflect Energex's total efficient 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 Energex to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for Energex; 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 clause 6.18.5(f) which requires Energex's tariffs to be based on LRMC.	Section 3.2.8 (Standard Control Services) Section 4.5.3 (Alternative Control Services)
6.18.5(h)	Energex must consider the impact on customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with clauses 6.18.5(e) to 6.18.5(g) to the extent Energex considers reasonably necessary having regard to: (1) the desirability for tariffs to comply with the pricing principles referred to in clauses 6.18.5(f) and 6.18.5(g), albeit after a reasonable period of transition (which may extend over more than one regulatory control period); (2) the extent to which customers can choose the tariff to which they are assigned; and (3) the extent to which customers are able to mitigate the impact of changes in tariffs through their usage decisions.	Section 5.1. Further information on how we meet this pricing principle is also available in our TSS.
6.18.5(i)	The structure of each tariff must be reasonably capable of being understood by 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	Section 3.2.9. Section 2.6 of the TSS

Clause	Obligation	Demonstration in this Pricing Proposal
	undertaken with, those customers.	
6.18.5(j)	A tariff must comply with the NER and all applicable regulatory instruments.	Appendix 5.
6.18.6(b)	Energex must demonstrate that the weighted average to be raised from a tariff class for a particular regulatory control year of a regulatory control period does not exceed the corresponding expected weighted average revenue for the preceding regulatory year in that regulatory year by more than the “permissible percentage” defined in clause 6.18.6(c).	Section 3.2.5.
6.18.7(a)	Energex’s Pricing Proposal must demonstrate that tariffs passed on to customers include the charges to be incurred by Energex for DPPC.	Section 3.3.3.
6.18.7(b)	Energex must demonstrate that the DPPC charges passed on to customers do not exceed the estimated DPPC charges adjusted for over or under recovery in the previous regulatory year.	Section 3.3.4.
6.18.7(c))	Energex must demonstrate that any DPPC over or under recovery is calculated in a way that: (1) is consistent with the method determined by the AER in the relevant distribution determination for Energex; (2) ensures that Energex is able to recover from retail customers no more and no less than the DPPC it incurs; and (3) adjusts for an appropriate cost of capital consistent with the allowed rate of return used in the relevant determination for the relevant regulatory year.	Section 3.3.4.
6.18.7(d)	Energex must demonstrate that is does not recover DPPC to the extent these are: (1) recovered through Energex’s annual revenue requirement; (2) recovered through tariffs designed to pass on jurisdictional scheme amounts under clause 6.18.7A; or (3) recovered from another DNSP.	Section 3.3.3.
6.18.7A(a)	Energex’s Pricing Proposal must provide for tariffs designed to pass on to customers Energex’s jurisdictional scheme amounts for approved jurisdictional schemes.	Section.3.4
6.18.7A(b)	Energex’s Pricing Proposal must demonstrate that the amount to be passed on to customers for a particular regulatory year must not exceed the estimated amount of jurisdictional scheme amounts for Energex’s approved jurisdictional schemes adjusted for over or under recovery calculated in accordance with clause 6.18.7A(c).	Section 3.4.1 and (confidential) Tariff Approval Model.
6.18.7A(c)	Energex must demonstrate that the over and under recovery has been calculated in a way that: (1) is consistent with the method determined by the AER	Section 3.4.1 and (confidential) Tariff Approval Model.

Clause	Obligation	Demonstration in this Pricing Proposal
	for jurisdictional scheme amounts in the relevant distribution determination; (2) ensures Energex is able to recover from customers no more and no less than the jurisdictional scheme amounts it incurs; (3) adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year.	
6.18.9(a)(3)	Energex must maintain on its website a statement of Energex's tariff classes and the tariffs applicable to each tariff class.	Tariff classes and tariffs to be updated on Energex's website upon AER's approval of the 2018-19 pricing proposal.
6.18.9(b)	Energex must publish all information set out in clause 6.18.9(a)(3) on its website 5 business days from the date the AER publishes Energex's approved Pricing Proposal.	This Pricing Proposal and non-confidential supporting attachments will be published on Energex's website by the appropriate dates.
6.19.2(a) and (b)	Subject to the Law and the NER, all information about a service applicant or distribution network user used by Energex for the purposes of distribution service pricing is confidential information. No requirement in this Chapter 6 to publish information about a tariff class is to be construed as requiring publication of information about an individual retail customer.	Energex does not publish site-specific information relating to individual customers. Our confidentiality claims are set out in Appendix 7.

Table A4- 2 Compliance with the Distribution Determination – Energex Determination 2015-2020

Section	Obligation	Demonstration of compliance
Attachment 14, Section 14.1, Figure 14.1 and Appendix A.	Energex must demonstrate compliance with the control mechanism for standard control services in accordance with the set revenue cap formulae – including adjustments for DUOS revenue under or over recovery in accordance with Appendix A of Attachment 14.	Section 3.2.1.
Attachment 14, Section 14.1	For Standard Control Services, apply the X factor for each year of the regulatory control period as determined in the PTRM and annually revised for the return on debt update in accordance with the formula specified in Attachment 3 – rate of return – of the Distribution Determination.	Section 3.2.1.
Attachment 14, Section 14.1, Figure 14.2.	Energex must demonstrate that the side constraints applied to the price movements of each tariff class are consistent with the side constraint formulae.	Section 3.2.5.
Attachment 14, Section 14.4.5	To the extent possible, Energex's pricing proposal should publicly disclose the separate charging parameters relating to DUOS, designated pricing proposal charges and jurisdictional scheme amount.	Appendix 1.
Attachment 14, Section 14.1, Appendix B.	Energex must submit as part of its annual pricing proposal, a record of the amount of revenue recovered from DPPC and associated payments in accordance with Appendix B of Attachment 14.	Section 3.3.4.
Attachment 14, Section 14.1, Appendix C.	Energex must report to the AER as part of its annual pricing proposal its jurisdictional scheme recovery amounts in accordance with Appendix C of Attachment 14.	Section 3.4.
Attachment 14, Section 14.1, Appendix D.	Energex must set out in its pricing proposal a method of how it will review and assess the basis on which a customer is charged.	Section 2.3 and Section 4.4.
Attachment 16, Section 16.2, Section 16.3.	Energex must demonstrate the application of a price cap as the form of control for ancillary network services. The AER's control mechanism formulae must be applied to fee based services, quoted services and individual Type 5 and 6 meters.	Section 4.3.2.

Appendix 5: Glossaries

Table A5- 1

Acronyms and abbreviations

Abbreviation	Description
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AR	Annual Smoothed Revenue
ARR	Annual Revenue Requirement
CAC	Connection Asset Customers
Capex	Capital Expenditure
CPI	Consumer Price Index
CT	Current transformer
DCOS	Distribution Cost of Supply
DNSP	Distribution Network Service Provider
DPPC	Designated Pricing Proposal Charges (previously known as TUOS)
DUOS	Distribution Use of System
EG	Embedded Generators
ENA	Energy Network Australia
EOO	Luminaires owned and operated by Energex
FiT	Feed-in Tariff (Solar FiT) under the Queensland Solar Bonus Scheme
GOO	Luminaires gifted to Energex by a council and operated by Energex
HV	High Voltage
ICC	Individually Calculated Customers
LCC	Large Customer Connection
LRMC	Long Run Marginal Cost
LV	Low Voltage
MAR	Maximum Allowable Revenue
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NMI	National Meter Identifier
NTC	Network Tariff Code
NUOS	Network Use of System
O&M	Operating and Maintenance Allowance (Opex)
Opex	Operating and Maintenance Expenditure

PV	Photovoltaic (Solar PV)
PV	Present Value
QAO	Queensland Audit Office
QCA	Queensland Competition Authority
RAB	Regulatory Asset Base
SAC	Standard Asset Customers
STPIS	Service Target Performance Incentive Scheme
TAR	Total Annual Revenue
TNCP	Transmission Network Connection Point
TNSP	Transmission Network Service Provider
TSS	Tariff Structure Statement
TUOS	Transmission Use of System (now known as DPPC)
WACC	Weighted Average Cost of Capital
WAR	Weighted Average Revenue

Table A5- 2 Units of measurement used throughout this document

Base Unit	Unit name	Multiples used in this document
h	hour	GWh, kWh, MWh
V	volt	kV, kVA, MVA
VA	volt ampere	kVA, MVA
var	var	kvar
W	watt	W, kW, kWh, MW

Table A5- 3 Multiples of prefixes (units) used throughout this document

Prefix symbol	Prefix name	Prefix multiples by unit	Prefixes used in this document
G	giga	10^9	GWh
M	mega	1 million or 10^6	MW, MWh, MVA
k	kilo	1 thousand or 10^3	kV, kVA, kvar, kW, kWh

Table A5- 4 Definitions of terminology used throughout this document

Term	Abbreviation / Acronym	Definition
Alternative Control Service		Customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than by the local DNSP. This service class includes the provision, construction and maintenance of type 6 metering services, street lighting assets, and fee based and quoted services.
Australian Energy Market Commission	AEMC	A national, independent body that exists to make and amend the detailed rules for the NEM to ensure efficient, reliable and secure energy market frameworks which serve the long term interests of consumers.
AEMC Power of Choice Review		Conducted by the AEMC, the Power of choice review sets out a substantial reform package for the NEM to provide consumers with more opportunities to make informed choices about the way they use electricity and manage expenditure. The package of reforms proposed by the AEMC includes, among other things: • reform of distribution network pricing principles to improve consumer understanding of cost reflective prices and give customers more opportunity to be rewarded for changing their consumption patterns. • expand competition in metering services with a view to provide services that reflect consumer preferences at efficient prices.
Annual smoothed revenue	AR	Refer to AER, Final Decision Energex determination 2015-16 to 2019-20, Attachment 14 – Control Mechanism, October 2015.
Australian Energy Regulator	AER	The economic regulator of the NEM established under section 44AE of the *Competition and Consumer Act 2010* (Commonwealth).
Business hours	BH	8 am to 5 pm, Monday to Friday.
Capacity charge		This part of the tariff seeks to reflect the costs associated with providing network capacity required by a customer on a long term basis. It is levied on the basis of either contracted demand or forecasted capacity using prior year information. The charge is applied as a fixed dollar amount per kVA per month.
Capital expenditure	Capex	Expenditure typically resulting in an asset (or the amount Energex has spent on assets).
Charging parameter		The charges comprising a tariff. Parameters include demand, capacity, fixed and volume (flat or time-of-use) charges.
Common service		A service that ensures the integrity of a distribution system, benefits all distribution customers and cannot reasonably be allocated on a locational basis.

Term	Abbreviation / Acronym	Definition
Connection Asset Customers	CAC	Typically, those customers connected at 11 kV who are not allocated to the ICC tariff class.
Connection asset (Contributed or non-contributed)		Related to building connection assets at a customer's premises as well as the connection of these assets to the distribution network. Connection assets can be contributed (customer funded, then gifted to Energex) or non-contributed (Energex funded).
Connection point		The agreed point of supply established between a Network Service Provider and another Registered Participant, Non-Registered Customer or franchise customer. The meter is installed as close as possible to this location.
Customer		Refer to chapter 10 of the NER.
Daily supply charge (or Fixed charge)		For large customers, reflects the incremental costs that arise from the connection and management of the customer. For small customers, reflects the average capacity set aside on the shared network for a typical customer using the tariff.
Demand		The amount of electricity energy being consumed at a given time measured in either kilowatts (kW) or kilovolt amperes (kVA). The ratio between the two is the power factor.
Demand charge		This part of the tariff accounts for the actual demand a customer places on the electricity network. The actual demand levied for billing purposes is the metered monthly maximum demand. The charge is applied as: • a fixed dollar price per kW per month or kVA per month for DPPC charges, and • a fixed dollar price per kVA per month for DUOS charges (ICC, CAC and SAC demand based customers).
Demand tariff		The tariff has been structured to include a demand component so the customer's actual demand is reflected in the price they pay for their electricity.
Designated Pricing Proposal Charge	DPPC	Refers to the charges incurred for use of the transmission network; previously referred to as Transmission Use of System (TUOS).
Distribution Cost of Supply Model	DCOS	The Energex model used to allocate costs approved by the AER to the various tariff classes.
Distribution Use of System	DUOS	This refers to the network charges which recover the costs of providing Standard Control Services.
Economy		Secondary tariff whereby a customer's specified connected appliances are controlled by network equipment so that supply will be available for a minimum period of 18 hours per day

Term	Abbreviation / Acronym	Definition
		during time periods set at the absolute discretion of Energex.
Embedded Generator	EG	In line with the ENA classification, EGs are generally those generators with an installed capacity as follows: Medium: 1-5 MVA (LV or HV) or < 1 MVA (HV) Large: > 5 MVA
Energy (or usage)		Refer to the definition of Usage below.
Feed-in Tariff	FiT	The rate that is to be paid for the excess energy generated by customers and fed back into the electricity grid under the Queensland Solar Bonus Scheme. The FiT rate is determined by the Queensland Government and is paid by the purchaser of the excess energy.
Final Determination		A distribution Determination document published by the AER in its role as Energex's economic regulator that provides for distribution charges to increase during Energex's Regulatory Control Period. In this proposal, reference to the Final Determination refers to the 2015-2020 AER Final Determination.
High Voltage	HV	Refers to the network at 11 kV or above.
Individually Calculated Customer	ICC	Typically those customers connected at 110 kV or 33 kV, or connected at 11 kV and with electricity consumption greater than 40 GWh per year at a single connection point or demand greater than or equal to 10 MVA, or where a customer's circumstances mean that the average shared network charge becomes meaningless or distorted.
Large customer classification		As per tariff class assignment process for customers with consumption greater than 100 MWh per year.
Large customer connection	LCC	Large customer connections are those connections that fall within the tariff classes of Individually Calculated Customer (ICC) and Connection Asset Customer (CAC) including embedded generators with installed capacity greater than or equal to 30 kVA.
Long Run Marginal Cost	LRMC	An estimate of the cost (long term variable investment) of augmenting the existing network to provide sufficient capacity for one additional customer to connect to the network or an additional MW of demand.
Low Voltage	LV	Refers to the sub-11 kV network
Maximum Allowable Revenue	MAR	The maximum revenue which can be recovered through tariffs for the regulatory year. This terminology is no longer in use as per the AER's F&A.
Maximum demand		The maximum demand recorded at a customer's individual meter or the maximum demand placed on the electrical distribution network system at any time or at a specific time or

Term	Abbreviation / Acronym	Definition
		within a specific time period, such as a month. Maximum demand is an indication of the capacity required for a customer's connection or the electrical distribution network.
Micro Generator		AS4777-compliant generators with an installation size of less than 10 kW (single phase) or 30 kW (three phase) connected to the LV network.
Market Settlement and Transfer Solution	MSATS	The central repository for Standing Data for all NMIs in contestable markets.
National Electricity Law	NEL	The legislation that establishes the role of the AER as the economic regulator of the NEM and the regulatory framework under which the AER operates.
National Electricity Market	NEM	The interconnected electricity grid covering Queensland, New South Wales, Victoria, Tasmania, South Australia and the Australian Capital Territory.
National Electricity Rules	NER (the NER)	The legal provisions (enforced by the AER) that regulate the operation of the NEM and the national electricity systems, the activities of market participants and the provision of connection services to retail customers.
National Metering Identifier	NMI	A unique number assigned to each metering installation.
Network Coupling Point	NCP	The point at which connection assets join a distribution network, used to identify the distribution service price payable by a customer.
Network Tariff Code	NTC	Energex's nominated code that represents the network tariff being charged to customers for network services.
Network Use of System	NUOS	The tariff for use of the distribution and transmission networks. It is the sum of both Distribution Use of System (DUOS) and DPPC.
Non-demand tariff		The tariff is based around a fixed daily component and the actual usage (or energy), expressed in kWh, used by the customer.
Non-standard		Where specialist resources or extensive man-hours for a small customer connection are required to assess the applicants proposed changes to connection agreements or standard methods of connection to the DNSP's network.
Off-peak period		All hours which are outside Peak and Shoulder periods.
Operating expenditure	Opex	Opex is the combined total of maintenance and operating costs. Maintenance Costs are those that are directly and specifically attributable to the repair and maintenance of network assets, while Operating Costs are those that relate to

Term	Abbreviation / Acronym	Definition
		the day to day operations of Energex which are not maintenance costs.
Peak period		Peak periods for time-of-use usage tariffs are set out in Table A1-8 in Appendix 1 of this Pricing Proposal. Peak periods for time-of-use demand tariffs are set out in Table A1-9 in Appendix 1 of this Pricing Proposal.
Power factor		Power factor is the ratio of kW to kVA, and is a useful measure of the efficiency in the use of the network infrastructure. The closer the power factor is to one (1), the more efficiently the network assets are utilised. Power factor = kW / kVA
Preliminary Decision		A Preliminary Decision is produced by the AER in its role as Energex's economic regulator. A Preliminary Decision is an interim Determination for the forthcoming regulatory period provided to Energex by the AER, prior to the release of a Final Determination. In this proposal, reference to the Preliminary Decision refers to the Preliminary Decision Energex determination 2015-16 to 2019-20.
Price path		Outlines the escalation factors to be applied to the initial price over the *Regulatory Control Period.*
Pricing objectives		Objectives established by Energex to complement (and ensure compliance with) the pricing principles set out in the NER, and to provide clarity when formulating tariffs.
Pricing principles		The pricing principles are established in clause 6.18.5 of the NER and provide guidance to Energex for setting tariffs.
Pricing Proposal		This document. Prepared by Energex in accordance with clause 6.18.2 of the NER. It is provided to the AER for approval and outlines how Energex will collect its revenue during the relevant regulatory year.
Queensland Government Solar Bonus Scheme	SBS FiT	A program that pays residential and other small energy customers for the surplus electricity generated from roof-top solar photovoltaic (PV) systems that is exported to the Queensland electricity grid.
Regulatory Control Period		A standard Regulatory Control Period for DNSPs is a period of not less than 5 regulatory years. Energex's current Regulatory Control Period is 2015-20, commencing 1 July 2015.
Regulatory depreciation		Also referred to as the return of capital – the sum of the (negative) straight–line depreciation and the (positive) annual inflation effect on the opening regulatory asset base (RAB).
Regulatory year		A specific year within the regulatory control period.
Return on capital		The return necessary to achieve a fair and reasonable rate of return on the assets necessarily invested in the business.

Term	Abbreviation / Acronym	Definition
S-banking		Mechanism allowing Energex to propose delaying a portion of the STPIS revenue increment or decrement to reduce price volatility to customers in accordance with clauses 6.4.3(a)(6) and 6.4.3(b)(6).
Service Target Performance Incentive Scheme	STPIS	A scheme developed and published by the AER in accordance with clause 6.6.2 of the NER, that provides incentives (that may include targets) for DNSPs (including Energex) to maintain and improve network performance.
Shoulder period		The hours between 7 am to 4 pm and 8 pm to 10 pm, Monday to Friday and 7 am to 10 pm weekends. For residential time-of-use tariff (NTC8900).
Side constraint		A side constraint is an upper limit on price increases applied at the tariff class level for SCS and is calculated in accordance with clause 6.18.6 of the NER by taking into account volume forecasts, CPI, X Factor, STPIS and Capital Contributions. The purpose of a side constraint is to mitigate the impact of prices on customers from one year to the next within a regulatory control period.
Site-specific charge		This charge is calculated for a site and is specific to the individual connection point.
Small customer classification		As per tariff class assignment process for customers with consumption less than 100 MWh per year.
Smart control		Secondary tariff whereby a customer’s specified permanently connected appliances are connected to audio frequency load control relays. The tariff is only available to residential customers with advanced metering for both the primary and secondary tariffs. This tariff has been developed to complement Energex’s demand tariffs and to incentivise residential customers to invest in emerging technologies (such as batteries and electric vehicles) that will benefit the network by targeting localised peaks.
Solar Photovoltaic	Solar PV	A system that uses sunlight to generate electricity for residential use. The system provides power for the premises with any excess production feeding into the electricity grid.
Standard Asset Customer		Generally those customers connected to the LV network.
Standard Control Service	SCS	Distribution services that are central to electricity supply and therefore relied on by most (if not all) customers. This service classification includes network services (e.g. construction, maintenance and repair of the network), some connection services (e.g. small customer connections) and Type 7 metering services (i.e. unmetered connections such as traffic lights).
Street lights		Lamps in common use for major road lighting including:

Term	Abbreviation / Acronym	Definition
(Major)		a) High Pressure Sodium 100 watt (S100) and above; b) Metal Halide 150 watt (H150) and above; and c) Mercury Vapour 250 watt (M250) and above.
Street lights (Minor)		All lamps in common use for minor road lighting, including Mercury Vapour, High Pressure Sodium and Fluorescent.
Summer Peak Window		The summer peak window is the period during which the top-up charge for the Residential Lifestyle Tariff applies. It is defined in Table A1-11 in Appendix 1 of this Pricing Proposal.
Super economy		Secondary tariff whereby a customer's specified permanently connected appliances are controlled by network equipment so that supply will be permanently available for a minimum period of 8 hours at the absolute discretion of Energex but usually between the hours of 10:00 pm and 6:00 am.
Tariff		The set of charges applied to a customer in the respective billing period. A tariff consists of one or more charging parameters that comprise the total tariff rate.
Tariff class		A class of customers for one or more *direct control services* who are subject to a particular tariff or particular tariffs (as per chapter 10 of the NER).
Tariff Schedule		The Tariff Schedule is published by Energex annually at the beginning of the financial year and outlines its tariffs for Standard Control Services and Alternative Control Services. It also provides information about how Energex assigns customers to tariff classes and the internal review process undertaken if a customer requests a review of a decision. The Tariff Schedule applies for the duration of the relevant financial year.
Tariff Structure Statement	TSS	Document prepared in accordance with Part I of chapter 6 of the NER, setting out Energex's network price structures and indicative tariffs that will apply over each year of the regulatory control period. Energex submitted its 2017-20 TSS proposal to the AER in November 2015. Once approved, the TSS will take effect from 1 July 2017.
Time-of-use	ToU	Refers to tariffs that vary according to the time of day at which the electricity is consumed. The Time-of-use periods include Off-peak, Peak and Shoulder
Total annual revenue	TAR	Refer to AER, Final Decision Energex determination 2015-16 to 2019-20, Attachment 14 – Control Mechanism, October 2015.
Transmission Use of System	TUOS	Superseded terminology for DPPC which are charges incurred for use of the transmission network.
Unmetered supply		A customer who takes supply where no meter is installed at the connection point.
Usage (or		The amount of electricity consumed by a customer (or all

Term	Abbreviation / Acronym	Definition
energy)		customers) over a period of time. Energy is measured in terms of watt hours (Wh), kilowatt hours (kWh), megawatt hours (MWh) or gigawatt hours (GWh).
Usage charge		This part of the tariff seeks to reflect costs not directly allocated to network drivers and costs that are proportional to the size of the customer. The energy consumption (kWh) for the period, as recorded by the customer's meter, is utilised to calculate this part of the tariff charge. This charge is applied as a fixed amount (cents) per kilowatt hour (kWh), i.e. c/kWh.
Usage charge - Off-peak		This charge is applicable to those customers who are on a Residential and/or Business Time-of-Use tariff. The energy consumption (kWh) during off-peak periods (refer to Off-peak Period for times), as recorded by the customer's meter, is utilised to calculate this part of the tariff. This charge is applied as a fixed amount (cents) per kilowatt hour (kWh), i.e. c/kWh.
Usage charge - Peak		This charge is applicable to those customers who are on a Residential and/or Business Time-of-Use tariff. The energy consumption (kWh) during peak periods (refer to Peak Period for times), as recorded by the customer's meter, is utilised to calculate this part of the tariff. This charge is applied as a fixed amount (cents) per kilowatt hour (kWh) i.e. c/kWh.
Usage charge - Shoulder		This charge is applicable to those customers who are on a Residential Time-of-Use tariff. The energy consumption (kWh) during shoulder periods (refer to Shoulder Period for times), as recorded by the customer's meter, is utilised to calculate this part of the tariff. This charge is applied as a fixed amount (cents) per kilowatt hour (kWh), i.e. c/kWh.
Weighted Average Cost of Capital	WACC	The return a business must earn on an existing asset base. For Energex, the WACC is set by the AER in a Determination for a specific regulatory control period.
Weighted Average Revenue	WAR	This is the average revenue that is expected to be recovered by tariff class during the relevant regulatory control year.
X Factor		Under the CPI – X form, prices or allowed revenues are adjusted annually for inflation (CPI) less an adjustment factor 'X'. The X Factor represents the change in real prices or revenues each year, so the DNSP can recover the costs that it expects to incur over the regulatory control period.

Appendix 7 - Confidentiality template

Title, page and paragraph number of the document containing the confidential information	Description of the confidential information	Topic the confidential information relates to (e.g. capex, opex, the rate of return)	Provide a brief explanation of why the confidential information falls into the selected category	Specify reasons supporting how and why detriment would be caused from disclosing the confidential information	Provide any reasons supporting why the identified detriment is not outweighed by the public benefit (especially public benefits such as the effect on the long term interests of consumers)
Energex's Tariff Approval Model	Individually Calculated Customers (ICC) Site Specific tariffs.	2018-19 proposed tariffs for the ICC tariff class.	Site specific prices are not published due to the confidentiality requirements of the customer. Energex will provide these site-specific tariffs directly to the customer and their retailer.	Personal Information	There is little or no public benefit to disclosing Individual Calculated Customers' prices. However, there would be significant detriment to competition and the customer's commercial position if this information is disclosed.
Energex's Tariff Approval Model	Connection Asset Customers (CAC) Site Specific Tariffs	2018-19 proposed tariffs for the CAC tariff class.	Site specific prices are not published due to the confidentiality requirements of the customer. Energex will provide these site-specific tariffs directly to the customer and their retailer.	Personal Information	There is little or no public benefit to disclosing CAC site specific prices. However, there would be significant detriment to competition and the customer's commercial position if this information is disclosed.